PERMIT TO CONSTRUCT

COMPANY NAME: Tesoro Refining & Marketing Co. LLC
Tesoro Los Angeles Refinery – Carson Operations

Facility ID: 174655

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Carson, CA 90749

EQUIPMENT ADDRESS: 2350 E. 223rd Street
Carson, CA 90810

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
Process 1: CRUDE DISTILLATION					
System 5: NO. 51 VACUUM DISTILLATION UNIT					S11.X1, S13.2, S31.5, S31.X1, S56.1
TANK, SURGE, FEED, RPV 6955, WITH GAS BLANKET, LENGTH: 45 FT; DIAMETER: 13 FT A/N: ~~552808~~ 567643	D35				
POT, STRAINER, LIGHT GAS OIL/DIESEL, RW 7194-289.02, HEIGHT: 4 FT 6 IN; DIAMETER: 2 FT A/N: 567643	DX1				L341.X1
POT, STRAINER, LIGHT GAS OIL/DIESEL, RW 7197-289.02, HEIGHT: 4 FT 6 IN; DIAMETER: 2 FT A/N: 567643	DX2				L341.X1
TOWER, VACUUM, ~~RPV 2501~~ RW 5967-289.01, HEIGHT: 135 FT; DIAMETER: 31 FT 6 IN A/N: ~~552808~~ 567643	D2726				L341.X1

EJECTOR, RW 247/248, 51 VACUUM TOWER OVERHEAD, 150 PSIG STEAM, 1st STAGE, 2 IN PARALLEL A/N: 567643	DX3				
EJECTOR, RW 249/250, 51 VACUUM TOWER OVERHEAD, 150 PSIG STEAM, 2nd STAGE, 2 IN PARALLEL A/N: 567643	DX4				
EJECTOR, RW 251/252, 51 VACUUM TOWER OVERHEAD, 150 PSIG STEAM, 3rd STAGE, 2 IN PARALLEL A/N: 567643	DX5				
KNOCK OUT POT, RPV 3240, OFF-GASES, HEIGHT: 8 FT ; DIAMETER: 2 FT A/N: ~~552808~~ 567643	D38				
DRUM, SEAL, RW 6927, LENGTH: 18 FT 6 IN; DIAMETER: 6 FT A/N: ~~552808~~ 567643	D2727				
POT, BLOWDOWN FLASH, RPV-5550, HEIGHT: 7 FT 8 IN; DIAMETER: 4 FT A/N: ~~552808~~ 567643	D41				
DRUM, QUENCH, RPV 5546, HEIGHT: 13 FT; DIAMETER: 5 FT A/N: ~~552808~~ 567643	D42				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~552808~~ 567643	D2462			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-23-2003**]	~~H23.3~~, H23.36
System 8: VACUUM DISTILLATION UNIT HEATERS					S11.X1

HEATER, NO.51 VACUUM UNIT HEATER, BOX TYPE, NATURAL GAS, ~~REPLACING H-401 AND H-402~~, WITH LOW NOX BURNER, ~~300~~ 360 MMBTU/HR WITH A/N: ~~552828~~ 567649 BURNER, 32 BURNERS, NATURAL GAS, JOHN ZINK, MODEL PSMR-17, WITH LOW NOX BURNER, ~~300~~ 360 MMBTU/HR	D63	C1335	NOX: MAJOR SOURCE**	**CO**: 2000 PPMV (5) [**RULE 407, 4-2-1982**]; **CO**: 29.6 LBS/MMSCF NATURAL GAS [**RULE 1303(b)(2) -Offset, 5-10-1996**]; **PM**: (9) [**RULE 404, 2-7-1986**]; **PM**: 0.1 GRAINS/SCF (5) [**RULE 409, 8-7-1981**]; **PM**: 6.3 LBS/MMSCF NATURAL GAS [**RULE 1303(b)(2) -Offset, 5-10-1996**]; **VOC**: 5.9 LBS/MMSCF NATURAL GAS [**RULE 1303(b)(2) -Offset, 5-10-1996**]; **NOX**: 2.62 LBS/HR NATURAL GAS (7) [**RULE 2005, 6-3-2011**]	A63.30, A99.X1, A195.X1, C1.X1, ~~D29.3~~, D29.X1, D328.1, K67.2
Process 5: HYDROTREATING					
System 2: MID-BARREL DESULFURIZER					S11.X1, S13.2, S15.6, S31.X1, S56.1
REACTOR, RPV 3900, HEIGHT: 27 FT 9 IN; DIAMETER: 8 FT 6 IN A/N: ~~553163~~ 578248	D334				
SCRUBBER, RPV 3901, RECYCLE GAS MDEA, HEIGHT: 59 FT 6 IN; DIAMETER: 4 FT 6 IN A/N: ~~553163~~ 578248	D335				
COLUMN, STRIPPER, RPV 3902, STABILIZER SIDESTREAM, HEIGHT: 28 FT 6 IN; DIAMETER: 2 FT 6 IN A/N: ~~553163~~ 578248	D336				

COLUMN, STABILIZER, RPV 3903, DIAMETER: 6 FT/9 FT, HEIGHT: 70 FT 8 IN A/N: ~~553163~~ 578248	D337				
SCRUBBER, RPV 3904, STABILIZER OFF-GASES MDEA, HEIGHT: 49 FT; DIAMETER: 2 FT 6 IN A/N: ~~553163~~ 578248	D338				
TANK, FLASH, RPV 3909, REACTOR EFFLUENT, HEIGHT: 20 FT; DIAMETER: 7 FT A/N: ~~553163~~ 578248	D339				
VESSEL, SEPARATOR, RPV 3910, DESULFURIZER OIL-WATER, LENGTH: 10 FT; DIAMETER: 3 FT A/N: ~~553163~~ 578248	D340				
ACCUMULATOR, RPV 3911, STABILIZER OVERHEAD, HEIGHT: 10 FT; DIAMETER: 4 FT A/N: ~~553163~~ 578248	D341				
POT, COMPRESSOR SUCTION, RPV 3912, STABILIZER OFF-GAS, HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553163~~ 578248	D342				
KNOCK OUT POT, RPV 3913, HYDROGEN FEED GAS, HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553163~~ 578248	D343				
DRUM, KNOCK OUT, RPV 3915, RECYCLE GAS MDEA, HEIGHT: 7 FT; DIAMETER: 2 FT 6 IN A/N: ~~553163~~ 578248	D345				
DRUM, KNOCK OUT, RPV 3916, STABILIZER RELEASE OFF GAS, HEIGHT: 6 FT; DIAMETER: 2 FT A/N: ~~553163~~ 578248	D346				
VESSEL, SEPARATOR, RPV 3917, STABILIZER OFF-GAS, HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553163~~ 578248	D347				

FILTER, RPV 5654, FEED S, HEIGHT: 4 FT 5 IN; DIAMETER: 2 FT 6 IN A/N: ~~553163~~ 578248	D348				
FILTER, RPV 5655, FEED N, HEIGHT: 4 FT 5 IN; DIAMETER: 2 FT 6 IN A/N: ~~553163~~ 578248	D349				
COMPRESSOR, RW 0033-087.32, THREE STAGE RECYCLE & MAKEUP HYDROGEN, INGERSOLL-RAND 13075 SCFM. WITH PACKED GLAND A/N: ~~553163~~ 578248	D350				
COMPRESSOR, RW 0036-087.32, THREE STAGE RECYCLE & MAKEUP HYDROGEN, INGERSOLL-RAND 13075 SCFM. WITH PACKED GLAND A/N: ~~553163~~ 578248	D351				
COMPRESSOR, RW 0035-087.32, OFF GAS, INGERSOLL-RAND 622 SCFM. WITH PACKED GLAND A/N: ~~553163~~ 578248	D352				
COMPRESSOR, RW 0034-087.32, OFF GAS, INGERSOLL-RAND 622 SCFM. WITH PACKED GLAND A/N: ~~553163~~ 578248	D353				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~553163~~ 578248	D2483			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-20-2013**]	~~H23.3~~ H23.36
System 4: No. 1 LIGHT HYDROTREATING UNIT					S11.X1, S13.2, S15.6, S31.1, S31.X1, S56.1
TANK, SURGE, RPV 0207, LENGTH: 30 FT; DIAMETER: 10 FT A/N: ~~552914~~ 567645	D401				
POT, RPV 3010, STABILIZER REBOILER CONDENSATE, HEIGHT: 2 FT 8 IN; DIAMETER: 1 FT 4 IN A/N: ~~552914~~ 567645	D402				

REACTOR, RPV 3000, NO.1, HEIGHT: 7 FT 9 IN; DIAMETER: 5 FT 6 IN A/N: ~~552914~~ 567645	D403				
REACTOR, RPV 3001, NO.2, HEIGHT: 7 FT 9 IN; DIAMETER: 5 FT 6 IN A/N: ~~552914~~ 567645	D404				
REACTOR, RPV 3002, NO.3, HEIGHT: 9 FT 9 IN; DIAMETER: 5 FT 6 IN A/N: ~~552914~~ 567645	D405				
TANK, FLASH, RPV 3007, EFFLUENT, LENGTH: 15 FT; DIAMETER: 5 FT A/N: ~~552914~~ 567645	D406			**BENZENE**: (10) [**40CFR 61 Subpart FF, #2, 12-4 2003**]; **VOC**: 500 PPMV (8) [**40CFR 61 Subpart FF, 12-4-2003**]	H23.12
COLUMN, STABILIZER, RPV 3012, HEIGHT: 49 FT; DIAMETER: 6 FT 6 IN A/N: ~~552914~~ 567645	D407				
ACCUMULATOR, RPV 3013, STABILIZER OVERHEAD, HEIGHT: 23 FT 7 IN; DIAMETER: 4 FT A/N: ~~552914~~ 567645	D408			**BENZENE**: (10) [**40CFR 61 Subpart FF, #2, 12-4-2003**]; **VOC**: 500 PPMV (8) [**40CFR 61 Subpart FF, 12-4-2003**]	H23.12
ABSORBER, RPV 3020, HEIGHT: 61 FT 9 IN; DIAMETER: 3 FT A/N: ~~552914~~ 567645	D411				
VESSEL, MDEA CONTACTOR, RPV 3026, HEIGHT: 37 FT; DIAMETER: 2 FT 6 IN A/N: ~~552914~~ 567645	D412				
KNOCK OUT POT, RPV 3022, HYDROGEN RELEASE MDEA, HEIGHT: 6 FT; DIAMETER: 2 FT A/N: ~~552914~~ 567645	D413				
REACTOR, RPV 3027, NO.4, HEIGHT: 14 FT 9 IN; DIAMETER: 5 FT 6 IN A/N: ~~552914~~ 567645	D414				

FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~552914~~ 567645	D2485			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-23-2003**]	~~H23.3~~, H23.36
EJECTOR, STEAM, RW0047-154.1, SERVING FLASH DRUM RPV 3007 A/N: ~~552914~~ 567645	D2648				E193.4
VESSEL, PRODUCT COALESCER, RW 7182 289.02, LENGTH: 6 FT 6.5 IN; DIAMETER: 2 FT 10.25 IN A/N 567645	DX6				
POT, STABILIZER REBOILER, RPV 3011 A/N 567645	DX7				
System 5: NAPHTHA HDS UNIT					S11.X1, S13.2, S31.X1, ~~S46.1~~, ~~S46.2~~, S46.4, S56.1
TOWER, STRIPPER, RW 5809, DIA: 3 FT 6 IN/6 FT 6 IN, HEIGHT: 54 FT 5 IN A/N: ~~552910~~ 567646	D1420				
COLUMN, CONTACTOR, RW 5810, RELEASE HYDROGEN MDEA, HEIGHT: 50 FT 11 IN; DIAMETER: 3 FT A/N: ~~552910~~ 567646	D1421				
REACTOR, RW 5832, HEIGHT: 21 FT 1 IN; DIAMETER: 7 FT A/N: ~~552910~~ 567646	D1422				
KNOCK OUT POT, RW 5833, MAKE-UP HYDROGEN, HEIGHT: 7 FT 6 IN; DIAMETER: 2 FT A/N: ~~552910~~ 567646	D1423				
ACCUMULATOR, RW 5836, STRIPPER OVERHEAD, HEIGHT: 13 FT 9 IN; DIAMETER: 4 FT 3 IN A/N: ~~552910~~ 567646	D1424			**BENZENE**: (10) [**40CFR 61 Subpart FF, #2, 12-4-2003**]; **VOC**: 500 PPMV (8) [**40CFR 61 Subpart FF, 12-4-2003**]	H23.12

POT, CONDENSATE, RW 5834, STRIPPER REBOILER, HEIGHT: 3 FT; DIAMETER: 1 FT 6 IN A/N: ~~552910~~ 567646	D1425				
TANK, FLASH, RW 5838, HEIGHT: 29 FT; DIAMETER: 7 FT A/N: ~~552910~~ 567646	D1426				
TANK, SURGE, RW 5839, FEED, HEIGHT: 42 FT; DIAMETER: 10 FT A/N: ~~552910~~ 567646	D1427				
KNOCK OUT POT, NATURAL GAS FILTER, RW 5837, HEIGHT: 5 FT; DIAMETER: 2 FT A/N: ~~552910~~ 567646	D1432				
TOWER, ~~DEBUTANIZER, C2~~ DEPENTANIZER, RPV 941, HEIGHT: 127 FT 8 IN; DIAMETER: 9 FT A/N: ~~552971~~ 567646	D637				L341.X1
DRUM, ~~MIXED BUTANE FEED~~, SURGE, DEPENTANIZER BOTTOMS, RPV 955, HEIGHT: 36 FT ; DIAMETER: 11 FT A/N: ~~552971~~ 567646	D658				L341.X1
ACCUMULATOR, DEPENTANIZER, OVERHEAD, RPV 942, ~~DEBUTANIZER~~ HEIGHT: 31 FT 6 IN; DIAMETER: 9 FT A/N: ~~552971~~ 567646	D656				L341.X1
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~552910~~ 567646	D2488			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-23-2003**]	~~H23.3~~, H23.36
Process 8: HYDROCRACKING					
System 2: HYDROCRACKER UNIT(FRACTIONATION SECTION)					S11.X1, S13.2, S15.6, S31.9, S56.1
COLUMN, STRIPPER, RPV 3600, HEAVY HYDROCRACKATE, HEIGHT: 60 FT 6 IN; DIAMETER: 6 FT A/N: ~~552885~~ 578249	D607				

COLUMN, FRACTIONATOR, RPV 3601, HEIGHT: 136 FT; DIAMETER: 13 FT A/N: ~~552885~~ 578249	D608				
COLUMN, DEBUTANIZER TOWER, RPV 3603, HEIGHT: 91 FT; DIAMETER: 6 FT A/N: ~~552885~~ 578249	D610				
COLUMN, TREATER, RPV 3604, LIQUID AMINE, HEIGHT: 27 FT; DIAMETER: 7 FT A/N: ~~552885~~ 578249	D611				
SCRUBBER, RPV 3605, HEIGHT: 52 FT; DIAMETER: 3 FT A/N: ~~552885~~ 578249	D612				
SCRUBBER, RPV 3606, AMINE, HEIGHT: 66 FT 6 IN; DIAMETER: 3 FT A/N: ~~552885~~ 578249	D613				
ACCUMULATOR, RPV 3610, DEBUTANIZER OVERHEAD, LENGTH: 22 FT; DIAMETER: 6 FT A/N: ~~552885~~ 578249	D614				
ACCUMULATOR, RPV 3611, FRACTIONATOR OVERHEAD, LENGTH: 21 FT; DIAMETER: 7 FT A/N: ~~552885~~ 578249	D615				
ACCUMULATOR, RPV 3612, FRACTIONATOR HOT REFLUX, LENGTH: 32 FT; DIAMETER: 8 FT A/N: ~~552885~~ 578249	D616				
SETTLING TANK, RPV 3614, AMINE, LENGTH: 24 FT; DIAMETER: 6 FT 6 IN A/N: ~~552885~~ 578249	D617				
KNOCK OUT POT, RPV 3617, OVERHEAD GAS, HEIGHT: 10 FT 6 IN; DIAMETER: 3 FT A/N: ~~552885~~ 578249	D619				
COMPRESSOR, RW 22 087.32, NO. 3, FRACTIONATOR OVERHEAD GAS, UNIT L-83247 A/N: ~~552885~~ 578249	D622				

COMPRESSOR, RW 23 087.32, NO. 2, FRACTIONATOR OVERHEAD GAS, UNIT L-83248 A/N: ~~552885~~ 578249	D623				
COMPRESSOR, RW 24 087.32 NO. 1, FRACTIONATOR OVERHEAD GAS, UNIT L-83249 A/N: ~~552885~~ 578249	D624				
TOWER, STRIPPER, RPV 6233, DISTILLATE HYDROCRACKATE, HEIGHT: 52 FT 9 IN; DIAMETER: 7 FT A/N: ~~552885~~ 578249	D2070				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~552885~~ 578249	D2495			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-20-2013**]	~~H23.3~~, H23.36
Process 9: ALKYLATION AND POLYMERIZATION					
System 1: ~~C4~~ ALKYLATION UNIT					S11.X1, S13.2, S15.31, S31.1, S31.X1, ~~S46.1~~, S46.4, S56.1
TANK, SETTLING, RPV-5299, ACID, HEIGHT: 70 FT; DIAMETER: 15 FT A/N: ~~553177~~ 567647	D1479				
TANK, SETTLING, RPV-5300, ACID, HEIGHT: 70 FT; DIAMETER: 15 FT A/N: ~~553177~~ 567647	D1480				
TANK, SETTLING, RPV-5301, ACID, HEIGHT: 70 FT; DIAMETER: 15 FT A/N: ~~553177~~ 567647	D1481				
DRUM, SUCTION TRAP/FLASH, RPV 5303, HEIGHT: 56 FT; DIAMETER: 16 FT A/N: ~~553177~~ 567647	D1482				

ACCUMULATOR, RPV-5313, REFRIGERANT, HEIGHT: 16 FT 6 IN; DIAMETER: 5 FT 6 IN A/N: ~~553177~~ 567647	D1483				
VESSEL, COALESCER, RPV-5290, FEED, HEIGHT: 4 FT 4 IN; DIAMETER: 4 FT 6 IN A/N: ~~553177~~ 567647	D1485				
TANK, WASH, RPV-5316, ACID, HEIGHT: 53 FT; DIAMETER: 16 FT A/N: ~~553177~~ 567647	D1486				
TANK, WASH, RPV-5317, ALKALINE WATER, LENGTH: 45 FT; DIAMETER: 15 FT A/N: ~~553177~~ 567647	D1487				
VESSEL, ECONOMIZER, RPV 5310, HEIGHT: 30 FT; DIAMETER: 10 FT A/N: ~~553177~~ 567647	D1488				
ACCUMULATOR, RPV-5325, DEISOBUTANIZER OVERHEAD, LENGTH: 42 FT; DIAMETER: 14 FT A/N: ~~553177~~ 567647	D1489				
TANK, WASH, RPV-5314, ALKY, DEPROPANIZER CAUSTIC, LENGTH: 10 FT; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D1490				
VESSEL, COALESCER, RPV-5315, DEPROPANIZER FEED, LENGTH: 10 FT; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D1491				
DRUM, K.O., RPV-7135, ACID, HEIGHT: 3 FT 6 IN; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D1492				
STORAGE TANK, FIXED ROOF, RPV-5380, FRESH ACID, LENGTH: 50 FT; DIAMETER: 13 FT A/N: ~~553177~~ 567647	D1493				

STORAGE TANK, FIXED ROOF, RPV-5381, FRESH ACID, LENGTH: 50 FT; DIAMETER: 13 FT A/N: ~~553177~~ 567647	D1494				
TOWER, DEISOBUTANIZER, RPV 5318, HEIGHT: 162 FT 6 IN; DIAMETER: 12 FT 6 IN A/N: ~~553177~~ 567647	D1495				
REACTOR, CONTACTOR STRATCO, RPV 5291, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D1496				
REACTOR, CONTACTOR STRATCO, RPV 5292, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D1497				
REACTOR, CONTACTOR STRATCO, RPV 5293, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D1498				
REACTOR, CONTACTOR STRATCO, RPV 5294, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D1499				
REACTOR, CONTACTOR STRATCO, RPV 5295, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D1500				
REACTOR, CONTACTOR STRATCO, RPV 5296, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D1501				
COMPRESSOR, RW 47 087.05, REFRIGERATION (EFFLUENT), CENTRIFUGAL MULTI-STAGE A/N: ~~553177~~ 567647	D1502				
VESSEL, COALESCER, MEROX SAND FILTER, RPV 5285, HEIGHT: 17 FT 6 IN; DIAMETER: 9 FT 6 IN A/N: ~~553177~~ 567647	D1520				
TOWER, RW 5965, C5 SIDESTRIPPER FOR DEBUTANIZER, HEIGHT: 32 FT; DIAMETER: 4 FT A/N: ~~553177~~ 567647	D1522				

TOWER, ALKY DEPROPANIZER, RPV 842, HEIGHT: 76 FT; DIAMETER: 4 FT 6 IN A/N: ~~553177~~ 567647	D631				
TOWER, ALKY DEBUTANIZER, RPV-843, NO. 1A, HEIGHT: 109 FT 6 IN; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D632				L341.X1
VESSEL, COALESCER, RW 7184-289.02, AMYLENE FEED, HEIGHT: 6 FT 6.5 IN; DIAMETER: 2 FT 8 IN A/N: 567647	DX8				L341.X1
COLUMN, DEISOBUTANIZER, RPV 875, NO.1B, HEIGHT: 120 FT; DIAMETER: 5 FT A/N: ~~553177~~ 567647	D634				
TANK, SURGE, RPV 0211, NAPHTHA, HEIGHT: 8 FT; DIAMETER: 3 FT 5 IN A/N: ~~553177~~ 567647	D635				
TOWER, COKER DEPROP, RPV 951, HEIGHT: 75 FT 8 IN; DIAMETER: 4 FT A/N: ~~553177~~ 567647	D638				
TANK, SURGE, RPV 830, OLEFIN FEED, HEIGHT: 33 FT; DIAMETER: 10 FT A/N: ~~553177~~ 567647	D639				
TANK, SURGE, RPV 831, OLEFIN FEED, HEIGHT: 33 FT; DIAMETER: 10 FT A/N: ~~553177~~ 567647	D640				
TANK, SURGE, RPV 832, OLEFIN FEED, HEIGHT: 33 FT; DIAMETER: 10 FT A/N: ~~553177~~ 567647	D641				
TANK, EMERGENCY ALKYLATION, RPV 834, HEIGHT: 36 FT; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D642				
TANK, EMERGENCY ALKYLATION , RPV 835, HEIGHT: 36 FT 6 IN; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D643				

TANK, EMERGENCY ALKYLATION , RPV 836, HEIGHT: 32 FT; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D644				
TANK, EMERGENCY ALKYLATION , RPV 837, HEIGHT: 32 FT; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D645				
ACCUMULATOR, RPV 847, NO. 1A, ALKYLATION DEBUT OVERHEAD, LENGTH: 20 FT; DIAMETER: 5 FT A/N: ~~553177~~ 567647	D646				
DRUM, SPENT CAUSTIC DEGASSING , RPV 859, LENGTH: 20 FT; DIAMETER: 5 FT A/N: ~~553177~~ 567647	D647				
DRUM, DEGASSING, RPV 0884, PROCESS WASTE WATER, HEIGHT: 20 FT 6 IN; DIAMETER: 4 FT 11 IN A/N: ~~553177~~ 567647	D648				
DRUM, ACID BLOWDOWN NEUTRALIZING, RPV 972, HEIGHT: 10 FT; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D649				
TANK, SURGE, RPV 890, ISOBUTANE FEED, HEIGHT: 40 FT; DIAMETER: 12 FT 11 IN A/N: ~~553177~~ 567647	D650				
DRUM, ACID RELIEF BLOWDOWN, RPV 892, LENGTH: 40 FT; DIAMETER: 13 FT A/N: ~~553177~~ 567647	D651				
DRUM, DEGASSING, RPV-985, MEROX WATER WASH TOWER WATER, LENGTH: 13 FT 6 IN; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D652				
DRUM, RPV-966, SPENT ACID, LENGTH: 39 FT 6 IN; DIAMETER: 13 FT A/N: ~~553177~~ 567647	D659				

DRUM, RPV-967, SPENT ACID, LENGTH: 39 FT 6 IN; DIAMETER: 13 FT A/N: ~~553177~~ 567647	D660				
STORAGE TANK, RPV-969, NO.2 ALKYLATION ACID, LENGTH: 45 FT; DIAMETER: 12 FT A/N: ~~553177~~ 567647	D661				
STORAGE TANK, RPV-970, NO. A-371, NO.2 ALKYLATION ACID, LENGTH: 45 FT; DIAMETER: 12 FT A/N: ~~553177~~ 567647	D662				
DRUM, BLOWDOWN, RPV 971, MTBE/MEROX HYDROCARBON, HEIGHT: 10 FT; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D663				
TOWER, BUTANE MEROX EXTRACTOR, RPV 5360, HEIGHT: 72 FT 6 IN; DIAMETER: 6 FT 6 IN A/N: ~~553177~~ 567647	D1530				E204.7
TOWER, OXIDIZER, RPV 994, MEROX SOLUTION, HEIGHT: 30 FT; DIAMETER: 3 FT A/N: ~~553177~~ 567647	D665				
POT, RPV 5385, MEROX CATALYST ADDITION, HEIGHT: 4 FT; DIAMETER: 1 FT A/N: ~~553177~~ 567647	D666				
DRUM, BLOWDOWN, RPV 891, ACID, LENGTH: 40 FT; DIAMETER: 13 FT A/N: ~~553177~~ 567647	D667				
DRUM, BLOWDOWN, RPV 989, ALKY HYDROCARBON, HEIGHT: 16 FT 9 IN; DIAMETER: 8 FT 1 IN A/N: ~~553177~~ 567647	D668				
POT, MEROX FOUL AIR DRIP, RPV 6940, HEIGHT: 7 FT 4 IN; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D2948				

ACCUMULATOR, RPV 5494, NO. 1, ALKYLATION DEBUT OVERHEAD, LENGTH: 12 FT; DIAMETER: 4 FT A/N: ~~553177~~ 567647	D670				
DRUM, RPV 5302, ATMOSPHERIC FLASH, HEIGHT: 11 FT 8 IN; DIAMETER: 6 FT 6 IN A/N: ~~553177~~ 567647	D1527				
KNOCK OUT POT, RPV 5339, DEPROPANIZER OVERHEAD, HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D1528				
TANK, SURGE, RPV 5350, #314 , COKER DEPROPANIZER FEED, HEIGHT: 30 FT; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D1529				
KNOCK OUT POT, RPV 5377, COKER DEPROPANIZER, HEIGHT: 11 FT 8 IN; DIAMETER: 6 FT 6 IN A/N: ~~553177~~ 567647	D1531				
TOWER, RPV 5551, WATER KNOCKOUT DRUM, HEIGHT: 17 FT 9 IN; DIAMETER: 6 FT A/N: ~~553177~~ 567647	D1532				
KNOCK OUT POT, RW 6929, C4/OLEFIN FEED WATER (TK 311), HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D2949				
KNOCK OUT POT, RW 6930, C4/OLEFIN FEED WATER (TK 312), HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D2950				
KNOCK OUT POT, RW 6932, C4/OLEFIN FEED WATER (TK 313), HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D2951				

KNOCK OUT POT, RPV 5612, IC4/OLEFIN FEED WATER(TK330), HEIGHT: 4 FT; DIAMETER: 1 FT A/N: ~~553177~~ 567647	D1536				
KNOCK OUT POT, RPV 5614, DEPROPANIZER FEED WATER(TK314), HEIGHT: 3 FT; DIAMETER: 1 FT A/N: ~~553177~~ 567647	D1538				
VESSEL, SEPARATOR, RPV 5336, HYDROCARBON/CONDENSATE, HEIGHT: 6 FT 8 IN; DIAMETER: 7 FT 6 IN A/N: ~~553177~~ 567647	D2019				
ACCUMULATOR, RPV 856, SOLVENT RERUN TOWER OVERHEAD, LENGTH: 20 FT; DIAMETER: 5 FT A/N: ~~553177~~ 567647	D2044				
REACTOR, CONTACTOR STRATCO 4A, RW 6366, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D2146				
REACTOR, CONTACTOR STRATCO 4B, RW 6367, WITH A 500 H.P. AGITATOR A/N: ~~553177~~ 567647	D2147				
TANK, SETTLING, RW-6368, ACID, HEIGHT: 70 FT; DIAMETER: 15 FT A/N: ~~553177~~ 567647	D2148				
TOWER, RPV-5351, MEROX WATER WASH, HEIGHT: 74 FT; DIAMETER: 7 FT A/N: ~~553177~~ 567647	D1517				
TOWER, MEROX EXTRACTOR, RPV-5284, HEIGHT: 33 FT; DIAMETER: 7 FT A/N: ~~553177~~ 567647	D1521				
DRUM, WASH NAPHTHA SETTLER, RW 0059, HEIGHT: 10 FT; DIAMETER: 7 FT A/N: ~~553177~~ 567647	D2369				
VESSEL, COALESCER, RW 6430, MIXED C4 FEED, HEIGHT: 4 FT 4 IN; DIAMETER: 2 FT 8 IN A/N: ~~553177~~ 567647	D2370				

DRUM, CAUSTIC PREWASH, RW 6424, HEIGHT: 20 FT; DIAMETER: 11 FT A/N: ~~553177~~ 567647	D2371				
VESSEL, DISULFIDE SEPARATOR, RW 6425, LENGTH: 24 FT; DIAMETER: 6 FT 6 IN A/N: ~~553177~~ 567647	D2372	C910 C2413		**HAP**: (10) [**40CFR 63 Subpart CC, #2, 6-23-2003**]	
FILTER, DISULFIDE SAND, RW-6426, HEIGHT: 7 FT; DIAMETER: 2 FT A/N: ~~553177~~ 567647	D2373				
ACCUMULATOR, RPV-0852, DEPROPANIZER OVERHEAD, HEIGHT: 20 FT; DIAMETER: 5 FT A/N: ~~553177~~ 567647	D2889				
VESSEL, RPV-5382, ACID RELIEF BLOWDOWN NEUTRALIZING, HEIGHT: 10 FT; DIAMETER: 8 FT A/N: ~~553177~~ 567647	D2890				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~553177~~ 567647	D2496			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-23-2003**]	~~H23.3~~, H23.36
VESSEL, COALESCER, RW 6889-289.02, NET EFFLUENT/WATER WASH, LENGTH: 13 FT 6 IN; DIAMETER: 6 FT A/N: ~~553177~~ 567647	D2664				
MIXER, RW 6642-289.02, STATIC, NET EFFLUENT/ACID, DIAMETER: 8 IN A/N: ~~553177~~ 567647	D2665				
MIXER, RW 6641-289.02, STATIC, NET EFFLUENT/ALKALINE WATER, DIAMETER: 8 IN A/N: ~~553177~~ 567647	D2666				
MIXER, RW 6640-289.02, STATIC, NET EFFLUENT/WASH WATER, DIAMETER: 8 IN A/N: ~~553177~~ 567647	D2667				

System 9: ISO-OCTENE UNIT					S11.X1, S13.2, S31.4, ~~S46.1~~, S46.4, S56.1
~~ACCUMULATOR, RPV 942, DEBUTANIZER OVERHEAD, HEIGHT: 31 FT 6 IN; DIAMETER: 9 FT~~ ~~A/N: 552971~~	~~D656~~				
ACCUMULATOR, RPV 952, DEPROPANIZER OVERHEAD, LENGTH: 11 FT 6 IN; DIAMETER: 5 FT A/N: ~~552971~~ 575838	D657				
VESSEL, VAPORIZER, RPV 3232, NO.2 ALKYLATION AMMONIA, HEIGHT: 5 FT 4 IN; DIAMETER: 4 FT A/N: ~~552971~~ 575838	D664				
KNOCK OUT POT, VAPOR RECOVERY, RPV-912, HEIGHT: 7 FT; DIAMETER: 5 FT A/N: ~~552971~~ 575838	D1508				
REACTOR, DIMERIZATION, RPV 5355, HEIGHT: 29 FT; DIAMETER: 12 FT A/N: 552971 575838	D2719				~~E336.8~~
KNOCK OUT POT, RPV 5613, MIXED OLEFIN FEED WATER (TK316) A/N: ~~552971~~ 575838	D1537				
~~TOWER, DEBUTANIZER, C2 (RPV 941), HEIGHT: 127 FT 8 IN; DIAMETER: 9 FT~~ ~~A/N: 552971~~	~~D637~~				
~~DRUM, RPV 955, MIXED BUTANE FEED, HEIGHT: 36 FT ; DIAMETER: 11 FT~~ ~~A/N: 552971~~	~~D658~~				
DRUM, V-X1, ALCOHOL RECYCLE, HEIGHT: 12 FT; DIAMETER: 3 FT 6 IN A/N: ~~552971~~ 575838	D2720				

FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~552971~~ 575838	D2503			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-20-2013**]	H23.3
Process 14: LOADING AND UNLOADING					
System 11: LPG RAIL CAR LOADING/UNLOADING RACK					S11.X1, S31.X1, ~~S46.2~~, ~~S46.3~~, S46.4, S56.1
LOADING AND UNLOADING ARM, RAIL CAR, EIGHT (8), PROPYLENE/PROPANE/BUTANE, WITH TWO FLEXIBLE HOSES & ONE TWO INCH REPRESSURIZING HOSE TO VRS, DIAMETER: 2 IN A/N: ~~552883~~ 567648	D2131				
DRUM, SURGE, LPG UNLOADING, RW 7185-289.02, HEIGHT: 26 FT; DIAMETER: 8 FT 6 IN A/N 567648	DX9				L341.X1
DRUM, KNOCKOUT, LPG UNLOADING, RW 7186-289.02, HEIGHT: 8 FT; DIAMETER: 3 FT 6 IN A/N 567648	DX10				L341.X1
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~552883~~ 567648	D2539				~~H23.3~~, H23.36
Process 19: PETROLEUM MISCELLANEOUS					
System 9: REFINERY INTERCONNECTION					S11.X1, S31.X2, S56.1
FUGITIVE EMISSIONS, MISCELLANEOUS, REFINERY INTERCONNECTION PIPING, METERING SYSTEM, AND MISCELLANEOUS FUGITIVE COMPONENTS A/N: 575837	DX11			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-20-2013**]	H23.36, L341.X1
Process 21: AIR POLLUTION CONTROL PROCESS					
System 1: SOUTH AREA FLARE SYSTEM					S11.X1, S31.10, S58.2

FLARE, ELEVATED WITH STEAM INJECTION, NATURAL GAS, WITH 3 PILOT ASSEMBLIES,TIE-IN LINE TO FCCU FLARE FROM THE SOUTH UNITS, HEIGHT: 203 FT 6 IN; DIAMETER: 3 FT WITH A/N: ~~571391~~ 575841 BURNER, JOHN ZINK, MODEL STF-S-24	C1302	D809 D815		**CO**: 2000 PPMV (5) [**RULE 407, 4-2-1982**]; **PM**: 0.1 GRAINS/SCF (5) [**RULE 409, 8-7-1981**]	B61.8, D12.15, D323.1, E193.3, H23.29, H23.39
KNOCK OUT POT, RPV-0417, HEIGHT: 7 FT; DIAMETER: 5 FT A/N: ~~571391~~ 575841	D2795				
KNOCK OUT POT, FLARE STACK, HEIGHT: 21 FT 6 IN; DIAMETER: 9 FT A/N: ~~571391~~ 575841	D1303				
KNOCK OUT POT, RPV-303, SOUTH AREA FLARE PRIMARY, LENGTH: 40 FT; DIAMETER: 10 FT A/N: ~~571391~~ 575841	D1304				
DRUM, WATER SEAL, RW 6989, LENGTH: 25 FT; DIAMETER: 13 FT A/N: ~~571391~~ 575841	D2796				
KNOCK OUT POT, SOUTH FLARE LINE, RPV-1994, HEIGHT: 5 FT 9 IN; DIAMETER: 1 FT 4 IN A/N: ~~571391~~ 575841	D2809				
KNOCK OUT POT, NORTH FLARE LINE, RPV-1993, HEIGHT: 5 FT 9 IN; DIAMETER: 1 FT 4 IN A/N: ~~571391~~ 575841	D2810				
VESSEL, AUTOPUMP, SOUTH AREA FLARE, RW-6876-289.09, HEIGHT: 3 FT 11 IN; DIAMETER: 1 FT A/N: ~~571391~~ 575841	D2863				
VESSEL, AUTOPUMP, SOUTH AREA FLARE, RW-6877-289.09, HEIGHT: 3 FT 11 IN; DIAMETER: 1 FT A/N: ~~571391~~ 575841	D2864				

FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~571391~~ 575841	D2542			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-20-2013**]	H23.3
System 3: HYDROCRACKER FLARE SYSTEM					S11.X1, S31.10, S58.4
FLARE, ELEVATED WITH STEAM INJECTION, WITH A LIGHT GAS SEAL & 33 STEAM JETS, NATURAL GAS, SERVING AS BACKUP FOR THE UNITS HANDLED BY THE FCCU FLARE, HEIGHT: 161 FT 3 IN; DIAMETER: 2 FT 6 IN WITH A/N: ~~553114~~ 575840 BURNER, JOHN ZINK, MODEL STF-S-30	C1308			**CO**: 2000 PPMV (5) [**RULE 407, 4-2-1982**]; **PM**: 0.1 GRAINS/SCF (5) [**RULE 409, 8-7-1981**]	B61.8, D12.15, D323.1, E193.3, E193.25, ~~H23.12~~, H23.29, H23.39
DRUM, FLARE KNOCKOUT, RPV 3212, LENGTH: 12 FT; DIAMETER: 10 FT A/N: ~~553114~~ 575840	D1309			~~**BENZENE**: (10) [**40CFR 61 Subpart FF, #2, 12-4-2003**]; **VOC**: 500 PPMV (8) [**40CFR 61 Subpart FF, 12-4-2003**]~~	~~H23.12~~
DRUM, WATER SEAL, RW 7002, LENGTH: 40 FT; DIAMETER: 14 FT A/N: ~~553114~~ 575840	D2804				
VESSEL, AUTOPUMP, HCU FLARE, RW-6878-289.09, HEIGHT: 3 FT 11 IN; DIAMETER: 1 FT A/N: ~~553114~~ 575840	D2867				
VESSEL, AUTOPUMP, HCU FLARE, RW-6879-289.09, HEIGHT: 3 FT 11 IN; DIAMETER: 1 FT A/N: ~~553114~~ 575840	D2868				
MIST ELIMINATOR, RPV-3214, LENGTH: 28 FT 6 IN; DIAMETER: 12 FT A/N: ~~553114~~ 575840	D1310				
VESSEL, SEPARATOR, RPV 3213, STEAM, HEIGHT: 4 FT; DIAMETER: 2 FT A/N: ~~553114~~ 575840	D1311				

DRUM, RPV 3215, OIL ELIMINATOR, HEIGHT: 6 FT; DIAMETER: 5 FT A/N: ~~553114~~ 575840	D1312				
FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~553114~~ 575840	D2544			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-20-2013**]	H23.3
System 6: REFINERY FLARE NO.5 SYSTEM					S11.X1, S31.10, S58.6
FLARE, ELEVATED WITH STEAM INJECTION, NO.5 , WITH 3 PILOT ASSEMBLIES, FLAME FRONT GENERATOR & FLAME MONITOR, NATURAL GAS, WATER SEAL, MOLECULAR SEAL, REMOTE SMOKE DETECTOR & STEAM INJECTION CONTRL SYS, HEIGHT: 265 FT; DIAMETER: 3 FT 6 IN A/N: ~~553120~~ 575839 BURNER, FLAREGAS, MODEL 42" FHP	C1661			**CO**: 2000 PPMV (5) [**RULE 407, 4-2-1982**]; **PM**: 0.1 GRAINS/SCF (5) [**RULE 409, 8-7-1981**]	~~B61.4~~, B61.8, D12.15, ~~D90.16~~, D323.1, E193.3, ~~H23.1~~, ~~H23.12~~, H23.29, H23.39
KNOCK OUT POT, NO.5 FLARE, RW 6135, HEIGHT: 30 FT; DIAMETER: 12 FT A/N: ~~553120~~ 575839	D1662			~~**BENZENE**: (10) [**40CFR 61 Subpart FF, #2, 12-4-2003**]; **VOC**: 500 PPMV (8) [**40CFR 61 Subpart FF, 12-4-2003**]~~	~~H23.12~~
DRUM, WATER SEAL, RW 7025, LENGTH: 50 FT; DIAMETER: 14 FT A/N: ~~553120~~ 575839	D2806				
VESSEL, AUTOPUMP, NO. 5 FLARE, RW-6881-289.09, HEIGHT: 3 FT 11 IN; DIAMETER: 1 FT A/N: ~~553120~~ 575839	D2871				
VESSEL, AUTOPUMP, NO. 5 FLARE, RW-6882-289.09, HEIGHT: 3 FT 11 IN; DIAMETER: 1 FT A/N: ~~553120~~ 575839	D2872				

FUGITIVE EMISSIONS, MISCELLANEOUS A/N: ~~553120~~ 575839	D2547			**HAP**: (10) [**40CFR 63 Subpart CC, #5A, 6-23-2003**]	H23.3

BACKGROUND

Tesoro Refining & Marketing Co. LLC (Tesoro) has submitted eighteen applications to the District for modification of equipment and construction of new equipment at the Tesoro Los Angeles Refinery - Carson Operations (Facility ID: 174655). Nine applications were submitted on August 19, 2014 (subsequently, on May 13, 2015, Tesoro requested cancellation of two of these applications), six applications were submitted on June 9, 2015, and three applications were submitted on September 15, 2015. The applications are a part of the project entitled "Tesoro Los Angeles Refinery Integration and Compliance Project (LARIC)," under which operations at the Tesoro Los Angeles Refinery (LAR) Carson Operations (formerly the BP West Coast Products LLC Carson Refinery) are integrated with those of the Tesoro Los Angeles Refinery (LAR) Wilmington Operations (Facility ID: 800436). Permits to Construct (PCs) are sought for the equipment modifications. The applications submitted for the LAR Carson Operations facility include, the following:

- A/N 567642 – Title V/RECLAIM Permit Significant Revision;
- A/N 567643 for modification of No. 51 Vacuum Distillation Unit (Process 1, System 5);
- A/N 567644 for modification of No. 52 Vacuum Distillation Unit (Process 1, System 6), subsequently requested cancellation of this application;
- A/N 567645 for modification of No. 1 Light Hydrotreating Unit (Process 5, System 4);
- A/N 567646 for modification of Naphtha Hydrodesulfurization (HDS) Unit (Process 5, System 5);
- A/N 567647 for modification of Alkylation Unit (Process 9, System 1);
- A/N 567648 for modification of LPG Railcar Loading/Unloading Rack (Process 14, System 11);
- A/N 567649 for change of condition for No. 51 Vacuum Distillation Unit Heater (Device ID: D63);
- A/N 567650 for modification of Hydrocracker R2 Recycle Gas Heater (D627), subsequently requested cancellation of this application;
- A/N 575836 – Title V/RECLAIM Permit Significant Revision;
- A/N 575837 for construction of a new refinery interconnection system (Process 19, System 9) providing piping/metering between LAR Carson and LAR Wilmington Operations;
- A/N 575838 for modification of the Iso-Octene System (Process 9, System 9);

- A/N 575839 for modification of the No. 5 Flare System (Process 21, System 6);
- A/N 575840 for modification of the Hydrocracker Flare System (Process 21, System 3);
- A/N 575841 for modification of the South Area Flare System (Process 21, System 1);
- A/N 578247 for Title V/RECLAIM Permit Significant Revision;
- A/N 578248 for modification of Mid Barrel Desulfurizer Unit (Process 5, System 2)
- A/N 578249 for modification of the Hydrocracker Unit – Fractionation Section (Process 8, System 2).

The Tesoro LARIC Project elements fall roughly into the following categories:

- Increase heat capacity of Coker Heater H-100 (D33) at Tesoro LAR Wilmington Operations from 252 MMBtu/hr to 302.4 MMBtu/hr and increase the heat input capacity of the No. 51 Vacuum Unit Heater (D63) at Tesoro LAR Carson Operations from 300 MMBtu/hr to 360 MMBtu/hr. No physical modifications will be made to these heaters, as the burners currently installed are capable of firing at the higher heat rates.
- Recovering and upgrading distillate range material from feeds to the Fluid Cataltyic Cracking Unit (FCCU) to accommodate the retiring of the Tesoro LAR Wilmington Operations FCCU. Project elements include modifications to Tesoro LAR Carson Operations No. 51 Vacuum Distillation Unit and Hydrocracker Unit and the Tesoro LAR Wilmington Operations Hydrocracker Unit and Hydrotreating Unit No. 4.
- Tier III gasoline compliance project elements to enable further hydrotreating in the Tesoro LAR Carson Operations Light Hydrotreating Unit and Mid-Barrel Distillate Treater Unit and the Tesoro LAR Wilmington Operations Hydrotreating Units 1 and 2 to meet new EPA low sulfur fuel requirements.
- Gasoline flexibility project elements to restore gasoline production capability diminished by the retirement of the Tesoro LAR Wilmington Operations FCCU, including modification of the Tesoro LAR Carson Operations Alkylation Unit, repurposing the Iso-Octene debutanizer for use in the Naphtha Hydrodesulfurization Unit, and modification of the Liquified Petroleum Gas (LPG) railcar unloading facility to allow additional unloading capabilities.
- Interconnecting System (pipelines and metering stations), electrical interconnection, heat integration project elements and retiring the Tesoro LAR Wilmington Operations FCCU.
- Additional facilities to regenerate sulfuric acid on-site, improve jet fuel quality, upgrade and treat propane for commercial sales, and upgrade Liquified Petroleum Gas (LPG) rail facilities to enable fast unloading of railcars.
- Constructing six new 500,000 barrel storage tanks at the Tesoro Carson Crude Terminal and replacing two crude tanks at Tesoro LAR Wilmington Operations with larger 300,000 barrel storage tanks.

On June 1, 2013 Tesoro acquired the Carson Operations facility from BP West Coast Products LLC. The initial Title V permit for this facility was issued to BP West Coast

Products on September 1, 2009. Upon completion of the change of ownership, a Title V permit was issued to Tesoro LAR Carson Operations on July 12, 2013. Tesoro's Title V permit was renewed on January 29, 2016, under A/N 561341.

The Tesoro LARIC Project includes the equipment modifications at the LAR Carson Operations facility which are described below. This evaluation includes the proposed modifications shown below in italics; the remainder of the projects shown below (in regular font) will be processed under separate evaluations, as applications are submitted for the equipment modifications/additions. The equipment modifications/additions are more fully described in the Process Description section of this report.

- *Vacuum Unit No. 51 modification: The No. 51 Vacuum Unit will be modified to allow an increase in diesel production, by reducing vacuum gas oil production. The No. 51 Vacuum Distillation Unit Heater (Device ID: D63) will be re-rated from the current permit rating of 300 MMBtu/hr, to 360 MMBtu/hr.*
- *Light Hydrotreating Unit modification: The Light Hydrotreating Unit will be modified to more effectively remove sulfur from FCCU gasoline, for compliance with federally mandated Tier 3 gasoline sulfur specifications. The modified Light Hydrotreating Unit will process a higher sulfur feed material derived from existing fractionation equipment.*
- *Naphtha Hydrodesulfurization Unit modification: The Naphtha Hydrodesulfurization Unit will be modified by the installation of new equipment to allow removal of contaminants from unit feed and sulfur from pentanes*. The reactor feed heater will also be upgraded with Ultra Low NO_x Burners, to further control NO_x emissions (future permitting).
- *Alkylation Unit modification: The Alkylation Unit will be modified to allow recovery of amylenes (C5 olefins) from FCCU gasoline in an existing fractionation tower and conversion of amylenes into low vapor pressure gasoline.*
- *Liquefied Petroleum Gas (LPG) Rail Car Loading/Unloading System modification: The LPG Rail Car Unloading Facility will be modified to allow for increased unloading of LPG (propane, propylene, butane, and butylenes, etc…) which serve as feedstock to the Alkylation Unit.*
- *Hydrocracker Unit: The Hydrocracker Unit capacity will be increased by 10 to 20 percent. The Hydrocracker Unit will be modified to enable it to treat distillate recovered from the No. 51 Vacuum Distillation Unit (as discussed above). This modification, to increase distillate yield, is required in order to allow for the planned shutdown of the FCCU at Tesoro LAR Wilmington Operations. According to Tesoro personnel, this modification will not increase the crude oil throughput capacity of the refinery.*

- *Mid Barrel Distillate Treater modification: The Mid Barrel Unit will be modified to enable it to desulfurize heavy FCCU naphtha. Interconnecting piping to/from the Light Hydrotreating Unit and Mid Barrel Distillate Treater will be installed.*
- *Iso-Octene Unit: Several vessels in the Iso-Octene Unit which are no longer in use will be repurposed for use in the Naphtha Hydrodesulfurization Unit.*
- *South Area Flare, Hydrocracker Flare and No. 5 Flare: Several new connections of Pressure Relief Valves, serving process units to be modified, will be made to the flares.*
- *Interconnection System: The Refinery Interconnection System will be constructed to provide pipelines and other necessary connection operations to further integrate the Tesoro LAR Carson and Wilmington Operations.*
- Fluid Catalytic Cracking Unit (FCCU) modification (future permitting): The Tesoro LAR Carson Operations FCCU will be modified to accept a portion of the Tesoro LAR Wilmington Operations gas oil feed. New piping will be run from the Tesoro LAR Wilmington Operations FCCU to the Tesoro LAR Carson Operations FCCU. The modifications to the Tesoro LAR Carson Operations FCCU include installation of a new feed surge drum upstream of the No. 2 Depropanizer Tower, to smooth out feed rate swings. The modifications will also allow recovery of propane from a stream that is normally fed to the fuel gas system.
- New Wet Jet Treater (future permitting): A new 50,000 BPD Wet Jet Treater will be installed to remove mercaptans and to reduce the Total Acid Number (TAN) of jet fuel.
- Naphtha Isomerization Unit modification (future permitting): The Naphtha Isomerization Unit will be modified to recover propane and heavier material from unit off-gas.
- Storage tank permits (future permitting): The permits for several storage tanks must be amended with respect to commodity stored and throughput limit.

In addition, this project includes constructions of new storage tanks at the Tesoro Logistics Operations LLC Carson Crude Terminal (Facility ID: 174694), which is located at 24696 S. Wilmington Avenue, Carson, CA.

Thus, the current set of applications (shown above in italics) represents the first phase of applications planned to be submitted by Tesoro for modifications at the LAR Carson Operations facility. The construction phase of the first portion of the project is scheduled to begin in the first quarter of 2016 and is expected to be completed by the end of 2017. The construction phase of the remainder of the project is expected to be completed by the end of 2019.

The proposed LARIC project will increase crude oil and feedstock processing capacity at the LAR Wilmington Operations facility by approximately 2%, or 6,000 Barrels Per Day (BPD).

Modifications to the LAR Wilmington Operations site, which are being evaluated in separate reports, include:

- modification of the Hydrocracking Unit (A/N 575876),
- construction of a refinery interconnection system (A/N 575874)
- modification of the flare system (A./N 575875)
- modification of Hydrotreater Units 4 (A/N 567619),
- an increase in rated heat input of Heater H-100 (D33) serving the Delayed Coking Unit (A/N 567439)
- construction of a new Propane Sales Treating Unit (future permitting),
- modification of Catalytic Reformer Unit 3 (future permitting),
- modification of Hydrotreater Units 1 and 2 (future permitting)
- construction of a new Sulfuric Acid Regeneration Plant (future permitting),
- replacement of two crude oil storage tanks with larger capacity tanks (future permitting),
- connection of a storage tank to the vapor recovery system (future permitting),
- and increasing the permitted throughput and change of service of four tanks (future permitting).

The LAR Wilmington Operations facility is located at 2101 East Pacific Coast Highway in the Wilmington district of Los Angeles and is contiguous with the Tesoro LAR Carson Operations site.

In addition to integration of the operations of the LAR Carson and Wilmington Operations facilities and enabling the refinery to comply with federally mandated Tier 3 gasoline specifications, the project is designed to provide Tesoro with flexibility in the production of gasoline, diesel fuel, and jet fuel (i.e. changing the gasoline to distillate (G/D) production ratio at the integrated refinery, in order to meet the changing market demand for various types of fuel products).

The LARIC Project includes the shutdown of the FCCU at the LAR Wilmington Operations site, resulting in expected reductions in emissions of criteria pollutants and Toxic Air Contaminants (TACs). Some of the emission reductions from the FCCU shutdown will be used to offset some of the emission increases from this project. However, Tesoro may in the future submit applications to obtain emission reduction credits from the FCCU shutdown. According to the latest revision of the Environmental Impact Report (EIR) for this project, the FCCU shutdown is scheduled to occur in June/July, 2017. The equipment listed below, which serves the FCCU, will be taken out of service. The combustion equipment, to be shut down, has a combined heat input rating of 559.3 MMBtu/hr.

- FCCU regenerator (FCCU coke burn), A/N 470269

- CO Boiler (300 MMBtu/Hr), A/N 470272
- H-2 Steam Superheater (37.4 MMBtu/Hr), A/N 469270
- H-3 Fresh Feed Heater (94.7 MMBtu/Hr), A/N 470270
- H-4 Hot Oil Loop Reboiler (127.2 MMBtu/Hr), A/N 470271
- H-5 Fresh Feed Heater (44 MMBtu/Hr), A/N 469272
- B-1 Startup Heater (84 MMBtu/Hr), A/N 473467

The permit history of the subject equipment is described in the table below.

Permit History

Application	**Process/ System**	**Device ID**	**Previous Permit**	**Date**	**Permit History**
567643	1/5	All	G24903/552808 G24227/425810 F50245/395515 D64251/249699 M62790/145819 M33753/C25460 P68787/C05802 P27442/A47091	6/19/2013 5/2/2013 3/15/2002 11/19/1992 5/9/1988 1980 1/7/1977 8/22/1968	The No. 51 Vacuum Distillation Unit is currently permitted under Permit No. G24903 (A/N 552808) issued on June 19, 2013. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, the equipment was permitted under Permit No. G24227 (A/N 425810), issued on May 2, 2013. Under this application the No. 51 Vacuum Distillation Unit was modified by installation of a new Vacuum Tower (D2726) and Seal Drum (D2727) and removal of the old Vacuum Tower (D36), Surge Tank (D37) and Knockout Pot (D40). Previously, this equipment was permitted under Permit No. F50245 (A/N 395515), issued on March 15, 2002. This application involved change of ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, this equipment was permitted under Permit No. D64251 (A/N 249699), issued on November 19, 1992. Under this application the No. 51 Vacuum Distillation Unit was modified by installation of a cutter stock pump. Previously, this equipment was permitted under Permit No. M62790 (A/N 145819), issued on May 9, 1988. Under this application the No. 51 Vacuum Distillation Unit was modified by increasing the HP rating of an asphalt bottoms pump from 350 HP to 450 HP Previously, this equipment was permitted under

				Permit No. M33753 (A/N C25460), issued in 1980. Under this application the No. 51 Vacuum Distillation Unit was modified by replacement of reciprocating vacuum jet condensate pumps with steam turbine driven pumps. Previously, this equipment was permitted under Permit No. P68787 (A/N C05802), issued on January 1, 1977. Under this application the No. 51 Vacuum Distillation Unit was modified by replacement of one side-stream circulation pump and an increase in the HP rating of two other pumps, from 400 HP to 500 HP. Previously, this equipment was permitted under Permit No. P27442 (A/N A47901), issued on August 22, 1968. Under this application the No. 51 Vacuum Distillation Unit was originally constructed.
567649	1/8	(D63)	G24922/552828 6/19/2013 F50297/395760 3/15/2002 F18092/174076 12/11/1998	The No. 51 Vacuum Distillation Unit Heater is currently permitted under Permit No. G24922 (A/N 552828), issued on June 19, 2013. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, the equipment was permitted under Permit No. F50297 (A/N 395760) issued on March 15, 2002. The permit action under this application was a change of ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, the equipment was permitted under Permit No. F18092 (A/N 174076) issued on December 11, 1998. Under this application the equipment was originally constructed and operated.
	5/2	All	G34919/553163 3/12/2015 G24877/552903 6/19/2013 G23775/429510 4/2/2013 F88728/460573 4/4/2007 F50183/395736 3/14/2002 P36939/A52615 3/27/1970	The Mid-Barrel Desulfurizer Unit is currently permitted under Permit No. G34919 (A/N 553163) issued on March 12, 2015. This modification involved connection of two Pressure Safety Valves (PSVs) in the Mid Barrel Desulfurizer Unit to the FCCU Flare System. Previously, the equipment was permitted under Permit No. G24877 (A/N 552903), issued on June 19, 2013. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, the equipment was permitted under Permit

				No. G23775 (A/N 429510), issued on April 2, 2013. This permit action involved listing of existing equipment; the devices were previously inactive in the facility permit and thus not listed. Previously, the equipment was permitted under Permit No. F88728 (A/N 460573), issued on April 4, 2007. This modification involved replacement of Diethanolamine (DEA), used in sour gas treatment (i.e. sulfur recovery), with Methyldiethanolamine (MDEA). Previously, this equipment was permitted under Permit No. F50183 (A/N 395736), issued on March 13, 2002. This application involved change of ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, the equipment was permitted under Permit No. P36939 (A/N A52615), issued on March 27, 1970. Under this application, the equipment was originally constructed and operated.
567645	5/4	All	G24995/552914 6/19/2013 G24590/433306 5/28/2013 460575/PC 4/3/2007 397242/PC 4/23/2002 284281/PC (Cancelled) 3/31/1994 M31869/106625 7/20/1983 P47290/A63153 12/2/1971	The No. 1 Light Hydrotreating Unit is currently permitted under Permit No. G24995 (A/N 552914) issued on June 19, 2013. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, the equipment was permitted under Permit No. G24590 (A/N 433306), issued on May 28, 2013. Under this application the permit equipment description for the No. 1 Light Hydrotreating Unit was amended to match the equipment operating in the field. This included: correction of the dimensions of Reactors (D403, D404, and D405); elimination of devices from the permit due to demolition (Compressor Knockout Pot - D409, Compressor Drip Pot - D410, and Stabilizer Overhead Vapor Compressor - D415); and updating the equipment ID number for Steam Ejector (D2648). A Permit to Construct was issued for this equipment on April 3, 2007, under A/N 460575. This modification involved replacement of Diethanolamine (DEA), used in sour gas treatment (i.e. sulfur recovery), with Methyldiethanolamine (MDEA). A Permit to Construct was issued for this equipment

				on April 23, 2002, under A/N 397242. This project involved a modification to comply with the requirements for production of CARB Phase III Reformulated Gasoline. Specifically, this involved an increase in the desulfurization capacity of the unit. A Permit to Construct was issued for this equipment on March 31, 1994, under A/N 284281. This PC was cancelled on January 22, 2002. Previously, this equipment was permitted under Permit No. M31869 (A/N 106625), issued on July 20, 1983. Previously, the equipment was permitted under Permit No. P47290 (A/N A63153), issued on December 2, 1971.
567646	5/5	All	G24992/552910 6/19/2013 G16807/504702 2/15/2012 G3786/438619 7/21/2009 F88727/460576 4/4/2007 F52152/395594 5/16/2002 284271/PC 4/1/1994	The Naphtha Hydrodesulfurization Unit is currently permitted under Permit No. G24992 (A/N 552910) issued on June 19, 2013. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, this equipment was permitted under Permit No. G16807 (A/N 504702), issued on February 15, 2012. This project involved elimination of condition S15.2, which required that all sour gases from this system be vented to the Naphtha Isomerization Unit (P9S8). This incorrect venting requirement was eliminated, as venting requirements in the permit are adequately described by conditions S56.1 and S18.7. Previously, the equipment was permitted under Permit No. G3786 (A/N 438619), issued on July 21, 2009. This application involved amendment of the equipment description (dimensions) of Stripper Tower (D1420) and Flash Tank (D1426). The purpose of the submittal was to amend the facility permit to reflect actual operation in the field. This did not involve construction of new equipment or modification of existing equipment. Previously, the equipment was permitted under Permit No. F88727 (A/N 460576), issued on April 4, 2007. This project involved a change from Diethanolamine (DEA), used in sour gas treatment (i.e. sulfur recovery), to Methyl diethanolamine (MDEA).

				Previously, the equipment was permitted under Permit No. F52152 (A/N 395594) issued on May 16, 2002. This application involved change of ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, this equipment was issued a PC under A/N 284271 on April 1, 1994. Under this application the Naphtha Hydrodesulfurization (HDS) Unit was originally constructed and operated.
	8/2	All	G33735/552885 12/12/2014 502190/PC 8/26/2010 433307/PC 7/21/ 2009 460579/PC 4/3/2007 450841/PC 9/16/2006 F50258/395985 3/15/2002 D98575/305942 4/30/1996 286545/PC 3/31/1994 273204/PC 11/16/1992 M41777/112412 12/14/1984 M25870/C23275 8/11/1982	The Hydrocracker Unit (Fractionation Section) is currently permitted under Permit No. G33735 (A/N 552885) issued on December 12, 2014. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. A Permit to Construct was issued for this equipment on August 26, 2010, under A/N 502190. This modification involved venting of several existing and several new Pressure Relief Devices (PRDs) in the Hydrocracker Unit - Fractionation Section to the Hydrocracker Flare System. A Permit to Construct was issued for this equipment on July 21, 2009, under A/N 433307. This application involved clean-up of the facility permit prior to issuance of the initial Title V permit, to reflect actual operation in the field. Specifically, the dimensions of the Debutanizer Overhead Accumulator (D614) were corrected. A Permit to Construct was issued for this equipment on April 3, 2007, under A/N 460579. This modification involved replacement of Diethanolamine (DEA), used in sour gas treatment (i.e. sulfur recovery), with Methyldiethanolamine (MDEA). A Permit to Construct was issued for this equipment on September 19, 2006, under A/N 450841. Modifications under this application involved an increase in production of ultra-low sulfur diesel fuel, resulting from an increase in the feed rate to the Hydrocracker Unit by 10%. Previously, this equipment is permitted under Permit No. F79736 (A/N 435120), issued on December 12, 2005. This application involved an Administrative Change to the permit to revise the equipment

				description for several devices and to eliminate devices which were demolished (Device IDs: D605 and D606). Previously, this equipment is permitted under Permit No. F50285 (A/N 395985), issued on March 15, 2002. Under this application the equipment underwent ownership change from ARCO Products Co. to BP West Coast Products LLC. This equipment was previously permitted under D98575 (A/N 305942), issued on April 30, 1996. This equipment was issued a Permit to Construct, under A/N 286545, on March 31, 1994 (current status: cancelled). This application involved equipment modification (i.e. addition, removal, and modification to equipment) based on the latest Clean Fuels Project. Previous to this, the equipment was issued a Permit to Construct under A/N 273204 (current status: cancelled) on November 16, 1992. Prior to this, the equipment was permitted under Permit No. M41777 (A/N 112412), issued on December 14, 1984. Previous to this, the equipment was permitted under Permit No. M25870 (A/N C24275), issued on August 11, 1982.
567647	9/1	All	G26185/553177 8/8/2013 552949/PC 6/18/2013 438620/PC 9/30/2008 462147/PC 3/21/2007 410695/PC 6/10/2003 400672/PC 8/29/2002 F53090/395972 6/26/2002 327610/PC 9/4/1997 323940/PC 2/6/1997 305939/PC 9/12/1995 285602/PC 4/4/1994 227109/PC 4/2/1992 M27385/C34476 2/1/1983 M01065/A85380 8/15/1977	The Alkylation Unit is currently permitted under Permit No. G26185 (A/N 553177) issued on August 8, 2013. The modification under this application consisted of venting a new replacement vessel, Air Drip Pot (RPV 6940), to the Refinery Vapor Recovery System and revising the permit to reflect the actual operation in the field. Previously, a PC was issued for this equipment on June 18, 2013, under A/N 552949. This permit action involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, a PC was issued for this equipment on September 30, 2008, under A/N 438620. This permit action involved updating the equipment description. Previously, a PC was issued for this equipment on

				March 21, 2007, under A/N 462147. This project involved connecting Pressure Relief Valves (PRVs) to a closed system venting to a flare. Previously, a PC was issued for this equipment on June 10, 2003, under A/N 410695. This project involved addition of a Butane Merox Extractor Tower. Previously, a PC was issued for this equipment on August 29, 2002, under A/N 400672. This project involved installation of a new Alkaline Water Wash Steam Heater, a new Net Effluent Water Wash Coalescer, and three mixers. Previously, the equipment was permitted under Permit No. F53090 (A/N 395972) issued on June 26, 2002. The permit action under this application was a change of ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, a PC was issued for this equipment on September 4, 1997, under A/N 327610. This application involved modification of the Alkylation Unit Merox Treating Section; this was part of the Polypropylene Production Project. Previously, a PC was issued for this equipment on February 6, 1997, under A/N 323940. This project involved construction of two new contactors, as a planned C5 Alkylation Unit was not built. This modification was needed to meet alkylate requirement for the California Air Resources Board (CARB) Reformulated Gasoline (RFG) Phase II project. Previously, a PC was issued for this equipment on September 12, 1995, under A/N 305939. This project involved design changes to the Alkylation Unit modifications permitted under A/N 285602. Previously, a PC was issued for this equipment on April 4, 1994, under A/N 285602. Under this RFG Phase II project, a fractionator (C5 side stripper) was added to separate pentane from the alkylate and to lower its Reid Vapor Pressure (RVP). The project also involved addition and removal of pumps. Previously, a PC was issued for this equipment on April 2, 1992, under A/N 227109. This project involved addition and removal of pumps.

				Previously, an Alkylation Unit was permitted under Permit No. M27385 (A/N C34476) issued on February 1, 1983. Previously, an Alkylation Unit was permitted under Permit No. M01065 (A/N A85380) issued on August 15, 1977.
575838	9/9	All	G25216/552971 6/20/2013 G24626/543210 5/30/2013 462148/PC 3/21/2007 427414/PC 4/6/2005 F61321/414004 6/10/2003 F52130/395968 5/16/2002	The Iso-Octene Unit is currently permitted under Permit No. G25216 (A/N 552971) issued on June 20, 2013. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, the equipment was permitted under Permit No. G24626 (A/N 543210) issued on May 30, 2013. Under this application, equipment which was no longer in service in this unit was eliminated from the permit. Previously, a PC was issued for the modification of this equipment on March 21, 2007, under A/N 462148. This project involved replacement of an atmospheric Pressure Relief Device (PRD) with a PRD connected to a closed vent system venting to the South Area Flare. Previously, a PC was issued for the modification of this equipment on April 6, 2005, under A/N 427414. Under this project the MTBE Unit was converted into an Iso-Octene Unit. This project was carried out to achieve compliance with the requirements of the CARB Phase 3/MTBE Phase-Out Project. Previously, this equipment was permitted under Permit No. F61321 (A/N 414004), issued on June 10, 2003. Under this Administrative Change application a Methanol Extractor Tower was removed from the MTBE Unit (P9S9) and moved to the Alkylation Unit (P9S1). Previously, the equipment was permitted under Permit No. F52160 (A/N 395968) issued on May 16, 2002. The permit action under this application was a change of ownership from ARCO Products Co. to BP West Coast Products LLC.
567648	14/11	All	G24971/552883 6/19/2013 F68164/419006 5/5/2004	The LPG Railcar Loading/Unloading Rack is currently permitted under Permit No. G24971 (A/N 552883)

			F52677/395999 6/11/6002 321943/PC 1/31/1997	issued on June 19, 2013. The permit action under this application involved change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, this equipment was permitted under Permit No. F68164 (A/N 419006), issued on May 5, 2004. Under this Administrative Change application, the permit for the LPG Loading/Unloading Rack was amended by elimination of applicability of 40 CFR 60 Subpart GGG. This was done, as it was determined that the LGP Loading/Unloading Rack did not meet the definition of “Process Unit” under this regulation. (Note: subsequently this regulation was re-applied to this equipment as its requirements were implemented facility-wide.) Previously, the equipment was permitted under Permit No. F52677 (A/N 395999) issued on June 11, 2002. The permit action under this application was a change of ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, a PC was issued for this equipment on January 31, 1997 under A/N 321943. Under this application the equipment was originally constructed and operated.
575837	19/9	All	None	The Refinery Interconnection System under Process 19: Miscellaneous is a new system for permitting the refinery integration piping, miscellaneous fugitive components and flow metering system. Thus, it has no previous permits.
575841	21/1	All	571391/PC 7/16/15 553112/PC 6/19/13 527742/PC 2/16/12 515465/PC 10/5/11 512088/PC 1216/10 499007/PC 3/25/10 484937/PC 9/30/08 462149/PC 3/21/07 F50715/395370 3/27/02 M43343/C17619 4/1/85 P68340/A87575 10/27/76 P32778/A46936 5/9/69	The South Area Flare was issued a PC on July 16, 2015 under A/N 571391. Under this application, the South Area Flare System was modified to receive vent gas from two Pressure Relief Valves (PRVs) in the Delayed Coking Unit No. 2 (P2S2). The South Area Flare System was issued a PC on June 19, 2013, under A/N 553112. Under this application the equipment underwent change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, a PC was issued on February 16, 2012 under A/N 527742 for modification of this equipment. Under this application the South Area Flare System was modified to receive vent gas from a PRV in the Delayed Coking Unit No. 1 (P2S1).

				Previously, a PC was issued on October 5, 2011 under A/N 515465 for modification of this equipment. Under this application the South Area Flare System was modified to receive vent gas from PRVs in the Superfractionation Unit (P4S1). Previously, a PC was issued on December 16, 2010 under A/N 512088 for modification of this equipment. Under this application the South Area Flare System was modified to receive vent gas from PRVs in the Superfractionation Unit (P4S1). Previously, a PC was issued on March 25, 2010 under A/N 499007 for modification of this equipment. Under this application the South Area Flare System was modified to receive vent gas from PRVs in the Superfractionation Unit (P4S1) and the Naphtha Splitter Unit (P4S2). Previously, a PC was issued on September 30, 2008 under A/N 484937 for modification of this equipment. Under this application the South Area Flare System was modified by addition of auto pumps which are used to remove collected liquids from the water seal tanks after flaring events, connections to receive additional vent gas from PRVs, amendment of the permit to indicate that natural gas is used as the pilot gas, and implementation of a permit condition to allow use of a thermocouple or infrared sensor for monitoring the pilot flame. Previously, a PC was issued on March 21, 2007 under A/N 462149 for modification of this equipment. Under this application the South Area Flare System was modified to receive vent gas from PRVs in the Alkylation Unit and the Iso-Octene Unit and by connection to the flare gas recovery system. Previously, the South Area Flare System was permitted under Permit No. F50715 (A/N 395370), issued on March 27, 2002. Under this application the equipment underwent change of ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, the South Area Flare System was permitted under Permit No. M43343 (A/N C17619), issued on April 1, 1985. Under this application the South Area Flare System was modified by connection

				to relief valves serving flash drums in the No. 3 and No. 4 DEA Regenerator. Previously, the South Area Flare System was permitted under Permit No. P68340 (A/N A87575), issued on October 27, 1976. Under this application the South Area Flare System was modified by connection of Pressure Relief Valves from the Claus Sulfur Plants, No. 1 Sulfur Plant Tail Gas Unit, No. 2 Sulfur Plant Tail Gas Unit, and the Sour Water Stripping Facilities. Previously, the South Area Flare System was permitted under Permit No. P32778 (A/N A46936), issued on May 9, 1969.
575840	21/3	All	G33736/553114 12/12/2014 511727/PC 12/16/2010 502191/PC 8/26/2010 488607/PC 6/2/2009 484939/PC 9/30/2008 458600/PC 3/21/2007 F87206/458604 1/30/2007 F50716/395738 3/27/2002 P35192/A52686 9/29/1969 P24036/A37799 1/18/1968	The Hydrocracker Flare System is currently permitted under Permit No. G33736 (A/N 553114), issued on December 12, 2014. Under this application the equipment underwent change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, a PC was issued on December 16, 2010 under A/N 511727 for modification of this equipment. The modification processed under this application was the connection of a PRV serving the Light Ends Depropanizer Feed Flash Drum (D297) in the Light Ends Depropanizer Unit (P4S3), to the Hydrocracker Flare. Previously, a PC was issued on August 26, 2010 under A/N 502191 for modification of this equipment. Under this application the Hydrocracker Flare was modified to receive vent gas from new and existing PSVs in the Hydrocracker Unit. Previously, a PC was issued on June 2, 2009 under A/N 488607 for modification of this equipment. Under this application the Hydrocracker Flare System was permitted to receive additional vents from PSVs in the Hydrocracker Unit – Reaction Section. However, the facility has decided not to complete these PSV tie-ins. Under this application the Hydrocracker Flare System was also permitted to serve as a back-up to the FCCU Flare System, during planned shutdowns of the FCCU Flare System. Previously, a PC was issued on September 30, 2008 under A/N 484939 for modification of this equipment.

				Under this application the Hydrocracker Flare System was modified by addition of two auto pumps serving the water seal tank. Previously, a PC was issued on March 21, 2007 under A/N 458600 for modification of this equipment. This project involved modification of the Hydrocracker Flare System, consisting of tie-in to the Flare Gas Recovery System. Previously, this equipment was permitted under Permit No. F87206 (A/N 458604), issued on January 30, 2007. The modification processed under this application was the connection of a PRV serving Light Ends Depropanizer Unit (P4S3), to the Hydrocracker Flare. Previously, the equipment was permitted under Permit No. F50716 (A/N 395738), issued on March 27, 2002. Under this application the equipment underwent Change of Ownership from ARCO Products Co. to BP West Coast Products LLC. Previously, the equipment was permitted under Permit No. P35192 (A/N A52686), issued on September 29, 1969. Under this application the Hydrocracker Flare was altered to serve the mid-barrel desulfurizer unit. Previously, the equipment was permitted under Permit No. P24036 (A/N A37799), issued on January 18, 1968. Under this application the Hydrocracker Flare was initially constructed and operated.
575839	21/6	All	553120/PC 6/19/2013 504384/PC 8/26/2010 484942/PC 9/30/2008 459257/PC 7/13/2007 458602/PC 3/21/2007 439108/PC 4/7/2006 331848/PC 3/12/1999 285551/PC 4/18/1994	A PC was issued for the No. 5 Flare System under A/N 553120 on June 19, 2013. Under this application the equipment underwent change of ownership from BP West Coast Products LLC to Tesoro Refining & Marketing Co. LLC. Previously, a PC was issued on August 26, 2010 under A/N 504384 for modification of this equipment. The modification processed under this application was the vent gas connection of PSVs from a Dehexanizer Feed Surge Vessel, serving the Coker Gasoline Fraction System (P4S7). Previously, a PC was issued on September 30, 2008 under A/N 484942 for modification of this equipment. Under this application the No. 5 Flare System was modified by addition of two auto pumps, which

				function to remove collected liquid from the water seal drum, after flaring events. Previously, a PC was issued on July 13, 2007 under A/N 459257 for modification of this equipment. Under this application the No. 5 Flare was modified to receive vent gas from PSVs serving the Coker Gas Fractionation Tower in the Superfractionation System (P4S1). Previously, a PC was issued on March 21, 2007 under A/N 458602 for modification of this equipment. This project involved modification of the No. 5 Flare System, consisting of tie-in to the Flare Gas Recovery System. Previously, a PC was issued on April 7, 2006 under A/N 439108 for modification of this equipment. Under this application the No. 5 Flare was modified to receive vent gas from PSVs serving Crude Tower #1, in the Crude Unit (P1S1). Previously, a PC was issued on March 12, 1999 under A/N 331848 for modification of this equipment. Under this application the No. 5 Flare was modified to receive vent gas from the Polypropylene Unit and the Coker Gas Merox Unit. Previously, a PC was issued on April 18, 1994 under A/N 285551. Under this application the No. 5 Flare was originally constructed. It was constructed to serve new process units (Naphtha HDS, Naphtha Isomerization, C5 Alkylation, C5 Alkylation Feed Treater, and No. 2 Hydrogen Plant) installed under the Reformulated Gasoline (RFG) Project to comply with CARB Phase II Clean Fuel requirements.

A search of the District database for the past three years indicates that there are no outstanding Notices of Violation (NOV) or Notices to Comply (NTC) associated with the subject equipment.

PROCESS DESCRIPTION

The table below contains a description of the subject processes/systems and the planned equipment modifications.

Process Description

Equipment	Process Description
No. 51 Vacuum Distillation Unit	The No. 51 Vacuum Distillation Unit distills Straight Run Resid produced in the crude distillation units into gas oils, vacuum tower bottoms and off gas. For this unit, process heat is supplied by a gas fired heater. Straight Run Resid (SRR) from the crude units is routed to a feed surge drum, through a gas fired feed heater, then to the vacuum tower. The vacuum tower is operated at reduced pressure, in order to reduce the boiling point temperatures of product constituents. In the vacuum tower, the SRR is divided into components, according to their boiling point temperatures. Distillation is conducted under vacuum, which is created by tower overhead ejectors, to allow product separation at lower temperatures than would be required under atmospheric pressure, thus avoiding the thermal cracking and coking which occur at higher temperatures. Under this project the No. 51 Vacuum Distillation Unit will be modified to provide flexibility to increase diesel fuel production, by decreasing vacuum gas oil production by up to 8,000 Barrels Per Day (BPD). The project involves modification of the Vacuum Tower (D2726), including modification of diesel collection trays, installation of a new 16 inch nozzle, and replacing the top six layers of Diesel PA Bed Packing. The equipment identification number of Vacuum Tower (device D2726) will be amended to RW 5967-289.01, as the currently listed identification number was for the original vacuum tower which was replaced under Permit No. G24227 (A/N 425810). The project also involves addition of new heat exchangers, strainers, electric pumps, as well as modification of associated piping and instrumentation. In addition, the permit for the No. 51 Vacuum Distillation Unit will be updated by listing of the three steam ejectors, which function to create a vacuum at the top of the vacuum tower There are three stages of ejectors (each stage having two ejectors in parallel) which utilize 150 psig steam as the motive force. Vent gases from the ejectors pass through Seal Drum (RW 6927) and are recovered by the Coker Low Line Vapor Recovery System (Process 2, System 6). The ejectors are existing equipment which were erroneously omitted from listing in the facility permit during the permitting of the new vacuum tower. The ejectors are described as follows: • Ejector, RW 247/248, 51 Vacuum Tower Overhead, 150 Psig Steam, 1st Stage, 2 in Parallel • Ejector, RW 249/250, 51 Vacuum Tower Overhead, 150 Psig Steam, 2nd Stage, 2 in Parallel • Ejector, RW 251/252, 51 Vacuum Tower Overhead, 150 Psig Steam,

	3rd Stage, 2 in Parallel The new equipment to be installed in this project, include: • Pot, Strainer, Light Gas Oil/Diesel, RW 7194-289.02, Height: 4 ft 6 in; Diameter: 2 ft • Pot, Strainer, Light Gas Oil/Diesel, RW 7197-289.02, Height: 4 ft 6 in; Diameter: 2 ft • Heat Exchanger, No. 1 Dehexanizer Feed/Vacuum Diesel Exchanger, RW 8999-289.03, 10 MMBtu/hr • Heat Exchanger, No. 1 Dehexanizer Feed/Vacuum Diesel Exchanger, RW 9000-289.03, 10 MMBtu/hr • Heat Exchanger, No. 2 Dehexanizer Feed/Vacuum Diesel Exchanger, RW 9001-289.03, 10 MMBtu/hr • Heat Exchanger, No. 2 Dehexanizer Feed/Vacuum Diesel Exchanger, RW 9002-289.03, 10 MMBtu/hr • Heat Exchanger, Vacuum Diesel Product Trim Cooler, RW 9003-289.03, 5.3 MMBtu/hr • Pump, Dehexanizer Towers Feed Booster Pump East, RW 3715-295.02, 2610 gpm @ 136 psi differential • Pump, Dehexanizer, Towers Feed Booster Pump West, RW 3720-295.02, 2610 gpm @ 136 psi differential
No. 51 Vacuum Distillation Unit Heater (D63)	The No. 51 Vacuum Distillation Unit Heater (D63) was constructed in 1994 to replace two heaters, Heater Nos. H-401 and H-402. At this site, it functions to heat feed to the Vacuum Distillation Tower. It is a "Box Type" heater firing natural gas with a rated heat input capacity of 300 MMBtu/hr. It is equipped with 32 John Zink Model No. PSMR-17 burners. The heater includes heat recovery, producing approximately 25,000 lbs/hr of 150 psig steam. For control of NO_x emissions the heater vents to Selective Catalytic Reduction (SCR) Unit (device C1335). SCR (device C1335) is a Modular Type unit equipped with Zeolite Honeycomb Catalyst with a volume of 120 cubic feet. The SCR system is designed to limit NO_x emissions to a maximum of 9 ppmv (at 3% O2). Under RECLAIM, this heater is designated as a "Major NO_x Source" and thus is monitored with a Continuous Emissions Monitoring System (CEMS). Permit condition A63.30 limits daily emissions of pollutants from the heater, as follows: 36 lbs ROG/day, 21 lbs CO/day, and 106 lbs PM/day. The following emissions factors were used under A/N 174076 for calculating controlled emissions from the heater: 0.03 lbs NO_x/MMBtu, 4.1 lbs CO/MMscf, 21 lbs PM/MMscf, 7 lbs ROG/MMscf, and 16.9 lbs SO_x/MMscf (note: original plan for this heater was for firing refinery fuel gas with a heating value of 1350 Btu/scf). The AEIS sheet under A/N 174076 contained the following

	controlled emissions rates: 1.5 lbs THC/hr, 9.0 lbs NO_x/hr, 3.8 lbs SO_x/hr, 0.9 lbs CO/hr, and 4.6 lbs PM_{10}/hr. Under this application the permit heat input capacity is proposed to be increased from 300 MMBtu/hr, to 360 MMBtu/hr. This permit action does not involve any physical modification of the equipment. The original equipment specification from supplier Brown & Root Braun states <u>"The Seller shall provide burners to fire the specified fuel. Burners shall be low NO_x type with staged fuel and integral flue gas recirculation design. The burner shall be sized for 120 percent of the design full load heat release and combustion air quantities, based on a draft of 0.1 water column at the arch level.</u>" Attachment #2 in the folder of A/N 567649 has the design specifications for this heater. Thus, the permit action to update the heat input capacity to 360 MMBtu/hr (120 percent of the previously listed heat input capacity of 300 MMBtu/hr) requires no modification of the heater. Under this application permit daily emissions limits for ROG, CO and PM under condition A63.30 will be amended. The daily emissions of pollutants will be amended from 36 lbs ROG/day, 21 lbs CO/day, and 106 lbs PM/day, to 48.67 lbs ROG/day, 243.33 lbs CO/day, and 52.14 lbs PM/day. The current permit limits are based on outdated emissions factors of 21 lbs PM/MMscf and 4.1 lbs CO/MMscf and the still valid emissions factor of 7 lbs ROG/day. The updated emissions rates are based on the following emissions factors: 7.5 lbs PM/day, 7 lbs ROG/day and 35 lbs CO/day. These are deemed to be more valid emissions factors than the factors used in the original permit evaluation for this heater. In addition, pollutant emissions rates per fuel input, will be limited as follows: 6.3 lbs PM/MMscf, 5.9 lbs ROG/MMscf, and 29.6 lbs CO/MMscf.
Mid Barrel Desulfurizer Unit	The Mid Barrel Desulfurizer Unit removes sulfur, nitrogen and trace metals from mid-boiling range distillate. It converts straight run diesel, straight run stove oil, and coker stove oil, and/or light cycle oil into desulfurized diesel, stove oil, or light cycle oil. Charge material and hydrogen gas are reacted in the presence of a catalyst. The process uses a hydrogen rich gas, which is recycled and mixed with make-up hydrogen to maintain a sufficiently high hydrogen concentration for effective reaction. The process produces hydrogen sulfide (H_2S) and ammonia (NH_3), which are stripped from the product stream. Liquid product is fractionated into appropriate boiling range fractions. Hydrogen sulfide (H_2S) is separated by absorption in methyldiethanolamine (MDEA). Under this project, the Mid Barrel Desulfurizer Unit will be modified to process the feedstock of the No.1 Light Hydrotreating Unit, heavy cat

	naphtha. This will enable the processing of this stream, when the No. 1 Light Hydrotreating Unit is out of service for maintenance and/or catalyst change out. The only modification required under this project is the construction of process piping, or "jump over" pipe, from the No. 1 Light Hydrotreating Unit to the Mid Barrel Desulfurizer Unit. No equipment changes within the Mid Barrel Desulfurizer Unit are required. Thus, the project involves addition of process piping and associated instrumentation.
No. 1 Light Hydrotreating Unit	The No. 1 Light Hydrotreating Unit treats light gasoline from the Fluid Catalytic Cracking Unit (FCCU), for removal of sulfur. Gasoline from the FCCU is mixed with high pressure hydrogen and heated to 640∘F. Hydrogenation results in conversion of sulfur to H_2S, some olefin saturation and a small amount of cracking. Excess hydrogen, cracked light ends hydrocarbons and H_2S are separated from the liquid in a flash drum. The gases from the flash drum are routed to an MDEA contactor, for removal of H_2S by scrubbing with MDEA. After MDEA treatment the excess hydrogen and cracked light ends are let down into a 200 psi hydrogen line; there is no hydrogen recirculation in this unit. Liquid hydrocarbon from the flash drum is sent through a stabilizer column for distillation. Overhead gases from the column are sent to a low pressure MDEA contactor for further treatment. The stabilized liquid product from the column is cooled and sent to storage as gasoline blend stock. In 2002, under A/N 397242, the No. 1 Light Hydrotreating Unit was modified by increase in its capacity from 14,500 Barrels Per Day (BPD) to 16,000 BPD. Under this project the No. 1 Light Hydrotreating Unit will be modified to more effectively remove sulfur from FCCU gasoline, for compliance with federally mandated Tier 3 gasoline sulfur specifications. The unit will process a higher sulfur feed material derived from existing fractionation equipment. The equipment to be modified under this project include: • Stabilizer Column (D407, RPV 3012) to be modified by installation of one or more new stripping steam injection nozzles and re-traying with a different design tray. • Stabilizer Reboiler (RPV 3011) to be modified by removal of internals (overflow weir and tube bundle) to provide stabilizer sump capacity. This equipment will be listed in the facility permit as a Stabilizer Reboiler Pot. • Overhead Accumulator (D408, RPV 3013), internals to be modified to improve hydrocarbon/water separation.

	• Heat Exchanger, RPV 2811, Jetcut Bottom Cooler West, 11.38 MMBtu/hr, to be modified with new shell side nozzles. • Heat Exchanger, RPV 2817, Jetcut Bottom Cooler East, 9.4 MMBtu/hr, to be modified with bigger tube side nozzles. • Feed Pump North, RW 1205-295.02, modified design specifications: 508 gpm at 685 psi differential. • Feed Pump South, RW 1204-295.02, modified design specifications: 508 gpm at 685 psi differential. New equipment to be installed under this project include: • Stabilizer Product Coalescer, RW 7182 289.02, Diameter: 2 feet 10.25 inches; Height: 6 feet 6.5 inches • Condensate Pot, Stabilizer Feed Preheater, Steam, RW 7181, Diameter: 2 feet 6 inches; Length: 5 feet • Condensate Pot, Feed Steam Preheater, RW 7183, Diameter: 2 feet; Length: 4 feet • Condenser, Stabilizer Overhead, RW 8996 (T), RW 8997 (B), 7.9 MMBtu/hr • Heat Exchanger, Heater Feed/Outlet Exchanger, RW 8993/8994, 13.0 MMBtu/hr • Heat Exchanger, Stabilizer Feed Preheater, RW 8995, 10.3 MMBtu/hr • Heat Exchanger, Feed Steam Preheater, RW 8998, 7.0 MMBtu/hr The project also involves modification of piping and instrumentation associated with the equipment listed above. This project also requires connection of a new Pressure Safety Valve, 25PSV5024, serving the new Stabilizer Product Coalescer (RW 7182), to a closed system venting to the Hydrocracker Flare System (Process 21, System 3).
Naphtha Hydro-desulfurization Unit	The Naphtha Hydrodesulfurization Unit functions to remove sulfur from feed to the Naphtha Isomerization Unit. It reacts hydrogen with naphtha feed in the presence of a catalyst, at elevated temperature and pressure, to remove organic sulfur and nitrogen. The feed to the unit consists of bottoms of the SFIA Depentanizer and Coker Fractionation Debutanizer. Hydrogen gas, which is obtained from the refinery hydrogen gas header, flows through a Make-Up Hydrogen Knockout Pot. It is compressed by a Hydrogen Booster Compressor, before being combined with the naphtha feed. In the reactor, organic sulfur is converted to hydrogen sulfide (H_2S)

and the nitrogen is converted into ammonia (NH_3). The hydrotreated reactor effluent then flows through a Flash Drum, where gases including H_2S are separated. H_2S is removed from the separated gases, by stripping with an MDEA solution. The H_2S-free, hydrogen rich gas is then sent to the Naphtha Isomerization Unit. The hydrotreated naphtha is sent to a Stripper Tower, for additional removal of H_2S and light hydrocarbons, and then sent to the Naphtha Isomerization Unit for further processing.

Under this application the Naphtha Hydrodesulfurization Unit will be modified by installation of equipment to allow removal of contaminants from unit feed and removal of sulfur from pentanes. The equipment planned for installation include knock out drums, air coolers, accumulators, heat exchangers, and electrically driven pumps. The project also involves modifications to associated piping and instrumentation.

This project also involves re-purposing equipment currently in service in the Iso-Octene Unit (Process 9, System 9), for service in the Naphtha Hydrodesulfurization Unit. These include:

- The Debutanizer Tower (D637, RPV 941) will be repurposed as a Depentanizer Tower. The modifications of this device include removal of the bottom six trays, addition of a chimney tray for reboiler feed, removal of Tray 29 feed nozzle, addition of a new nozzle and distributor at Trays 39 to 41, and modifications of trays above the feed tray for increased clearance/weir height. Other additions to the Depentanizer Tower include: one 18 inch reboiler feed nozzle, one 24 inch reboiler return nozzle, four 2 inch level transmitter nozzles, three 2 inch temperature transmitter nozzles, and one 8 inch feed nozzle.
- The Mixed Butane Feed Drum (D658, RPV 955) will be repurposed to function as a Depentanizer Bottoms Surge Drum. The modifications of this device include addition of one 2 inch vent nozzle and two 2 inch level transmitter nozzles.
- The Debutanizer Overhead Accumulator (D656, RPV 942) will be repurposed as a Depentanizer Overhead Accumulator. The modifications of this device include addition of an internal dip pipe with stilling well and two 2 inch level transmitter nozzles.

Other equipment to be modified, which are not listed in the facility permit, include:

- C4 Olefin Feed Pumps Middle/South (RW 2372 & RW 2373) will be modified to Depentanizer Bottoms Pumps Middle/South
- C4 Olefin Feed Pump North (RW 2832) will be modified to a Depentanizer Bottom Pump North
- Iso-Octene Column Reboiler (RPV 933) will be modified to a Depentanizer Reboiler Condensate Pot
- Iso-Octene Product Cooler (RPV 5359) will be modified to a Depentanizer Overhead Product Cooler
- C4 Olefin Feed Pumps North/South (RW 2446 & RW 2447) will be modified to Depentanizer Reflux Pumps East/West
- Debutanizer Distillate Cooler Bottom/Top (RPV 6420 & RPV 6421) will be modified to Depentanizer Bottoms Coolers Bottom/Top
- Debutanizer Overhead Condensers West/East top (RPV 943 & RPV 944) will be modified to Depentanizer Overhead Condensers West/East Top
- Debutanizer Overhead Condenser East/West Bottom (RPV 945 & RPV 946) will be converted to Depentanizer Overhead Condenser East/West Bottom

New equipment proposed to be installed, which will not be listed in the facility permit, include:

- Heat Exchanger, Depentanizer Feed/Bottom Exchanger Top/Bottom (E001A, E001B), each 3.58 MMBtu/hr
- Heat Exchanger, Depentanizer Reboiler (E002), 26.58 MMBtu/hr
- Pump, Depentanizer Condensate Pumps (RW New), East/West, each 75 gpm at 28 psi differential pressure.

This project also requires connection of five new Pressure Safety Valve (PSVs) to a closed system venting to the No. 5 Flare System (Process 21, System 6). The PSVs to be connected to the flare system are the following: 44PSV5045 (serving Device D637; Depentanizer Tower, RPV 941), 44PSV5043 (serving Device D656; Depentanizer Overhead Accumulator, RPV 942), 44PSV5046 (serving Device D658; Depentanizer Bottoms Surge Drum, RPV 955), 44PSV5042 (serving Straight Run Naphtha Depentanizer Bottoms Cooler (RPV 6420/6421)) and 44PSV-5051 (serving Straight Run Naphtha Depentanizer Overhead Product Cooler (RPV 5359)). Three of the PSVs (44PSV5043, 44PSV5045, 44PSV5046) will replace PSVs currently vented to the atmosphere (i.e. atmospheric PSVs). Thus, under this project these devices will be eliminated from condition S56.1, which lists devices with atmospheric PSVs. Currently, these devices are listed in condition S56.1, under Process 9, System 9. (Note: as a result of the elimination of

	atmospheric PSVs, which are subject to monitoring requirements under 1173(h)(1), Tesoro will be required to amend its Rule 1173 Compliance Plan.)
Hydrocracker Unit (Fractionation Section)	The Hydrocracker Unit processes high sulfur diesel feed into both ultra-low sulfur diesel fuel and gasoline blend components. The Hydrocracker Unit cracks long chain gas oil molecules into smaller molecules, using a catalytic process in a hydrogen-rich atmosphere. Cracking of long chain molecules occurs in a high temperature, high pressure environment. The process produces gasoline, reformer feed, and distillate products low in sulfur and nitrogen. Hydrogen is separated from the liquid reactor effluent and is recycled and mixed with fresh feed. Make up hydrogen from the hydrogen plant is compressed and fed to the unit by large reciprocating compressors. The Hydrocracker Unit processes a combined feed rate of approximately 50,000 barrels per day. Feed streams include approximately 13,000 barrels per day of FCC Jet Fuel, approximately 5,000 barrels per day of FCC Light Cycle Oil (LCO), approximately 9,000 barrels per day of coker diesel, and approximately 23,000 barrels per day of straight run diesel. In 2010, under A/N 501042, a project was undertaken to remove hydraulic and thermal constraints in the Hydrocracker Unit - Reaction Section, in order to increase the feed rate from 50,000 barrels per day to 55,000 barrels per day, when in a low conversion (diesel) operating mode. The 5,000 barrel per day feed rate increase results from an increase in straight run diesel throughput, from 23,000 barrels per day to 28,000 barrels per day. The project also involved upgrade of the Hydrocracker Unit water wash system. The Hydrocracker Unit - Fractionation Section separates the liquid products from the Reaction Section into gasoline and diesel blend components called Hydrocrackates. It utilizes a Fractionation Tower and Fractionation Reboiler. Products of the process include light hydrocrackate (LUX) and heavy hydrocrackate (HUX) in the gasoline boiling range, jet boiling range material (DUX), a diesel stream (BUX), and other light products. Under this project the Hydrocracker Unit will be modified to allow for processing of distillate recovered from other process units. Processing of recovered distillate will require increased hydrogen gas usage. The increased hydrogen gas will be provided by either increasing the recycle gas compressor speed, or from hydrogen obtained from an offsite supplier. However, Tesoro indicates that overall, this project will not result in an increase in hydrogen demand due to shutdown of other refinery units and associated elimination of products requiring hydrotreating.

	Modifications under this project will result in improved energy utilization/recovery in the Hydrocracker Unit. Heat exchanger (RW 6693) will be installed in order to improve the heat recovery from jet fuel products and to cool these products. This heat exchanger will generate 150 psig steam. For better cooling of fractionators bottoms (diesel product), a new identical bay will be added to the Fractionator Bottoms Air Cooler (RW 8992). The project also requires installation of pumps and associated piping and instrumentation. The new equipment is described as follows: ➢ Heat Exchanger, DUX Steam Generator, RW 6693 289.05, 6.33 MMBtu/hr ➢ Heat Exchanger, Fractionator Bottoms Air Cooler, RW 8992 289.03, 60.09 MMBtu/hr
Alkylation Unit	The Alkylation Unit is a process unit which converts propylene, butylene, and amylenes into gasoline range blend stock. In this unit, olefin feed is combined with isobutane (iC4) in the presence of liquid sulfuric acid catalyst to produce motor fuel alkylate which is a high-octane gasoline blend component. The reaction is carried out in eight contactors where hydrocarbons and acid are mixed by electrically driven impellers. The acid and hydrocarbons are then separated in acid settlers. The acid is recycled to the contactors, while the hydrocarbons are processed further to separate butanes from the alkylate product. Alkylate is washed to remove trace quantities of acid and then is fractionated to remove normal butane and isobutene, which are recycled back to the process. The butane stream (this stream also contains some propane) is compressed, cooled, and fractionated with the recovered isobutane being recycled to the contactors. The Alkylation Feed Merox Unit is used to remove sulfur compounds (H_2S and Mercaptans) from the mixed feed streams, which consist of butane, iso-butane, and olefins. The feed mixture is first contacted with low strength caustic wash, and then with higher strength caustic in the extractor, to remove sulfur compounds. The C4 compounds, which are low in sulfur, are then water washed and sent to the Alkylation Unit. Thus, the Merox Unit improves the Alkylation Unit operation and helps generate a high-octane product which is low in sulfur. Under this project the Alkylation Unit will be modified to separate amylenes (pentenes - C_5H_{10} - unsaturated hydrocarbons of the olefin series). This will provide flexibility to replace a portion of the gasoline production capacity lost by retiring the FCCU at Tesoro LAR Wilmington Operations. The modifications to process butylenes and amylenes include installation of a new Amylene Feed Coalescer (RW 7184-289.02), re-traying Debutanizer

	Tower (D632, RPV-843) with re-designed trays, and installation of heat exchangers and electrically driven pumps. The project also involves modification of associated piping and instrumentation. As the Alkylation Unit is being modified to enable it to process C5s in addition to C4s; the descriptor "C4" will be eliminated from the system name in the facility permit. The new equipment to be installed under this project include: • Vessel, Coalescer, Amylene Feed, RW 7184-289.02, Diameter: 32 in, Length: 6 ft 6.5 in • Heat Exchangers, C5 Olefin Feed/Effluent Exchangers, RW 9004-289.03, RW 9005-289.03, and RW 9006-289.03, 3 series, each 2.1 MMBtu/hr • Heat Exchanger, C5 Sidestripper Bottoms Cooler (top), RW 9007-289.03, 1.5 MMBtu/hr • Heat Exchanger, C5 Sidestripper Bottoms Cooler (bottom), RW 9013-289.03, 1.5 MMBtu/hr • Miscellaneous, Desuperheater, RW 0065-134.01 • Miscellaneous, Mixer, Net Effluent/Alkaline Water Static Mixer, RW 7195-289.09 Other equipment to be modified under this project include: • Pumps, Isobutane Charge Pumps (Isobutane Feed Pumps East/West), RW 2325 & 2326-295.02: modify by installation of maximum impellers (modified pumps each have a capacity of 300 gpm at 160 psi differential pressure) This project also requires connection of five new Pressure Safety Valve (PSVs) to closed systems venting to the South Area Flare System (Process 21, System 1) and to the No. 5 Flare System (Process 21, System 6). The PSVs to be connected to the South Area Flare System are the following: 40PSV5163 (serving the new Amylene Feed Coalescer (RW 7184)), 40PSV5162 (serving C5 Olefin Feed Effluent Exchanger – Shellside (RPV 9004/5/6)), and 40PSV5164 (serving C5 Olefin Feed Effluent Exchanger – Tubeside (RPV 9004/5/6)). The PSVs to be connected to the No. 5 Flare System are the following: 76PSV5008 (serving piping – propane line to the Alkylation Unit) and 76PSV5009 (serving piping – propylene line to the Alkylation Unit).
Iso-Octene Unit	The Iso-Octene Unit was commissioned in 2005 for the purpose of producing Iso-Octene, a gasoline blending component. In this unit an

	isobutylene rich olefin stream reacts with an alcohol rich recycle stream in a fixed bed reactor to form Iso-Octene. The reactor effluent is sent to a Debutanizer Column to separate reacted product from unreacted product. Distillate C4s, the top column product, are sent to the Alkylation Unit for further processing, while the bottom product is sent to the Iso-Octene Column for removal of alcohols. Iso-Octene, the bottom product of the column, is sent to the Hydrotreating Unit for hydrogenation. The facility has indicated in previous application submittals that the Iso-Octene Unit has been used sporadically and that elimination of equipment from this unit is not anticipated to affect refinery operations. Under this project several vessels, which are no longer in use, will be repurposed and used in the Naphtha Hydrodesulfurization Unit (Process 5, System 5). The vessels to be removed from the permit of the Iso-Octene Unit (Process 9, System 9) are listed below: Device ID: D637 - Debutanizer Tower (RPV 941) Device ID: D656 – Debutanizer Overhead Accumulator (RPV 942) Device ID: D658 - Mixed Butane Feed Drum (RPV 955) Under this permit action the tagging of the Dimerization Reactor (RPV 5355; Device ID: D2719) with condition E336.8 is eliminated. According to the information under A/N 472414, this reactor has a connection to the South Area Flare System for venting in case of emergency (fire). This connection is adequately permitted under conditions S56.1 and S58.2. Thus, the tagging with condition E336.8 is deemed to be superfluous and is eliminated.
LPG Railcar Loading/ Unloading	The LGP Railcar Loading/Unloading Rack transfers propylene, propane, or butane to railcars for shipment to offsite locations. This system is also used for receipt of these products into the refinery, for use in the refining process. It was constructed to support the export of mixed light ends (primarily propylene and propane) for commercial sales. It has eight loading/unloading arms, having a diameter of 2 inches, each with two flexible hoses. The system includes a 2 inch diameter pressurizing hose, which is connected to the refinery vapor recovery system. The system also includes five pumps (exempt from permitting under condition F25.1) which are equipped with dual mechanical seals and are vented to the refinery vapor recovery system. Under this application the LPG Railcar Loading/Unloading Rack will be modified to allow additional unloading capabilities. The LPG unloading rate will be increased, from 11,000 BPD to 15,000 BPD, during the high

Reid Vapor Pressure (RVP) season – during the winter months. No additional rail trips to the refinery will be required for the increased LPG unloaded by this system. No new loading/unloading arms will be constructed. The new equipment in the LPG unloading facility includes:

- Surge Drum, LPG Unloading, RW 7185-289.02, Diameter: 8 ft 6 in, Height: 26 ft; this surge drum has an operating pressure of 220 psig at 100◦F.
- Knockout Drum, LPG Unloading, RW 7186-289.02, Diameter: 3 ft 6 in, Height: 8 ft; this knockout drum has an operating pressure of 35 psig at 120◦F, it has a connection to the refinery vapor recovery system
- Vaporizer, LPG Repressurizing Vaporizer, utilizing 150 psig steam, Duty: 1.37 MMBtu/hr
- Pumps, LPG Unloading, RW 312-295.23 and RW 313-295.23, Unloading Pumps North/South, capacity of 450 gpm at 53 psi differential pressure
- Pumps, Propylene Transfer Pumps, RW 314-295.23 and RW 315-295.23, Propylene Transfer Pumps North/South, capacity of 100 gpm at 90 psi differential pressure, with connections to the refinery vapor recovery system

This project also involves installation/modification of piping and instrumentation associated with the equipment described above. The new LPG unloading system will have connections to storage tanks TK-352 and TK-353 at Tesoro LAR Carson Operations. Propylene Transfer Pumps North/South (RW 314 and RW 315) will be used to transfer LPG from Tanks TK-352 and TK-353 and to the Alkylation Unit at Tesoro LAR Wilmington Operations.

This project also requires connection of five new Pressure Safety Valve (PSVs) to a closed system venting to the No. 5 Flare System (Process 21, System 6). The PSVs to be connected to the flare system are the following: 74PSV5007 (serving new Knock Out Drum RW 7186), 74PSV5008 (serving new Vaporizer RW 9009), 74PSV5009 (serving new Surge Drum, RW 7185), 74PSV5013 (serving piping – propane truck loading header), and 74PSV5108 (serving Odorant Storage Tank D2139, RW 0056-289.02, this is a replacement of existing PSV which is currently connected to flare).

This project also involves an additional connection from this system to the refinery vapor recovery system. This connection is not expected to change the quantity or make-up of the vent gases sent to the refinery vapor recovery

	system. This connection also is not impacted by the capacity of the refinery vapor recovery system. Thus, this connection to the refinery vapor recovery system need not be evaluated under a permit application.
Refinery Interconnection System	The Tesoro LAR – Carson Operations Refinery Interconnection System will be used to provide piping and other necessary connection operations to further integrate Carson Operations and Wilmington Operations sites. This system will include a pipe bundle consisting of seven to fifteen pipelines ranging in size from four inches to 12 inches in diameter. The pipe bundle will exit the Carson Operations facility at the south east portion of the refinery and will be routed underneath Alameda Blvd, at a depth of approximately 80 feet, to an area near the Carson Operations Coke Barn, where it will be routed above ground. The pipe bundle will then be routed underneath Sepulveda Blvd. into the Wilmington Operations site. There the piping will be routed above ground on pipe racks, or ground level pipe supports, into the respective product and supply manifolds in the refinery. In addition, piping at the Carson Operations site will include metering equipment, PIG launching and receiving equipment, and in-line basket strainers. The in-line strainers are components designed to protect the metering equipment and are manufactured to ANSI B31.4 (liquids pipeline piping specifications). This project also requires connection of three new Pressure Safety Valve (PSVs) to a closed system venting to the South Area Flare System (Process 21, System 1). The PSVs to be connected to the flare system, which serve the Refinery Interconnection System, are the following: 75PSV207, 75PSV209, and 75PSV211. In addition, three Thermal Relief Valves (TRVs) serving LPG piping will be connected to a closed system venting to the South Area Flare System.

South Area Flare System

The South Area Flare System (also known as the Coker Flare) is a General Services Flare which receives process gas and emergency vent gas from a variety of processes/systems at the refinery. It has a John Zink burner, Model No. STF-S-24. It is equipped with natural gas fired pilots (3 pilots with a flow rate of 50 scf/hr per pilot). Natural gas is also used as purge gas in the flare. The flare height is 203.5 ft. and the flare tip diameter is 3 ft. Steam is injected at the tip of the flare through steam jets, to assist with mixing of combustion gases. The flare has a design capacity to treat 601,000 lbs/hr vent gas with a molecular weight of 63 lbs/lb-mole. Flare design capacity is a function of several parameters including the maximum recommended tip velocity (manufacturer supplied) and the molecular weight of relieving gas.

Under this project the new PSVs listed in the table below will be connected to a closed vent system, venting to the South Area Flare System.

Flare Connection	PSV Number	System / Connection Description
1	40PSV5164	Alkylation Unit (P9S1); C5 Olefin Feed Effluent Exchangers Tubeside (RPV 9004/5/6)
2	40PSV5162	Alkylation Unit (P9S1); C5 Olefin Feed Effluent Exchangers Shellside (RPV 9004/5/6)
3	40PSV5163	Alkylation Unit (P9S1); C5 Olefin Feed Coalescer (RPV 7184)
4	75PSV-207	Refinery Interconnection System (P19S9); Butylene Transfer Line (0109-6"-PCA-91103)
5	75PSV-209	Refinery Interconnection System (P19S9); Propylene Transfer Line (0124-4"-PDAQ-24410)
6	75PSV-211	Refinery Interconnection System (P19S9); n Butane Transfer Line (0109-6"-PCA-91104)

Note: In addition to these connections Tesoro plans to install three Thermal Relief Valves (TRVs) on LPG lines in the Refinery Interconnection System which will be connected to the South Area Flare.

The South Area Flare System was selected to receive vent gas from the Alkylation Unit and the Refinery Interconnection System for several reasons; especially its proximity to the connected equipment, the ability to coordinate the shutdown of the flare and the equipment vented to it, and its sufficient capacity to handle the worst possible release scenario. Permit condition S58.2 indicates that the South Area Flare System is already permitted to receive and handle vent gas from the Alkylation Unit (Process 9, System 1). Tesoro has prepared and submitted an evaluation of all major

PSV release scenarios to the South Area Flare (Attachment #6 A/N 575841). This assessment has determined that the connection of PSVs planned under this project will not result in an exceedance of the capacity for the South Area Flare System.

The PSVs tied into the South Area Flare have multiple relieving cases, either in unique relief or as part of a common relief scenario. Common release scenarios, which impact flare size, are described in the table below.

South Area Flare General Common Release Scenarios

Common Release Scenarios	Lbs/hr	MW	Flare Tip Mach No.
Total Plant Wide Failure	456,229	40	0.19
150# Steam Failure	598,165	61	0.20
#7 CW Tower Failure	601,055	63	0.20
Partial Power Failure (Sub 1K/1M)	381,938	64	0.12

The flare tip velocities are within the manufacturer (John Zink) recommended limits stated below:

1. 0.7 Mach for processing hydrocarbons with some inert gases such as CO_2, steam, etc…
2. 0.8 Mach for processing straight hydrocarbons
3. 0.9 Mach for processing hydrocarbons with 50 mole % or more hydrogen

The new PSVs have the following failure scenarios.

Flare Connection	PSV Number	Relief Scenario	Relief Load (lb/hr)	MW
Alkylation Unit				
1	40PSV-5164	External Fire only	15,251	64
2	40PSV-5162	External Fire only	22,268	63
3	40PSV-5163	External Fire only	6,720	63
Refinery Interconnecting Piping				
4	75PSV-207	Thermal only	1,590	SG = 0.6
5	75PSV-209	Thermal only	1,543	SG = 0.5
6	75PSV-211	Thermal only	1,162	SG = 0.6

	For this project Tesoro has evaluated the tie-ins and has determined the following: • The new PSVs do not contribute to any of the common relief scenarios that impact flare size. Thus, they do not change the back pressures on existing PSV during any of the common failure scenarios. • The new PSVs serving the Alkylation Unit contribute to the Alkylation Unit Fire Circle #2 release scenario. The additional relief load from the new PSVs results in an increase in back-pressure on existing PSVs. However, the increase in back-pressure is 50% or less of the corresponding set-pressure and thus within the allowable back-pressure for existing balanced bellows type PSVs. The combined load for the Alkylation Unit Fire Circle #2 relief scenario, including from new PSVs serving the Alkylation Unit, is 99,567 lbs/hr (MW = 59). This relief scenario is not the sizing basis of the South Area Flare. There are no significant impacts to the flare header from the tie-in of the new PSVs. • The additional load to the South Area Flare from the new PSVs tie-ins from the Alkylation Unit and Refinery Interconnection System will not cause the capacity of the flare to be exceeded.

Hydrocracker Flare System	The Hydrocracker Flare System receives process gas and emergency vent gas from a variety of processes/systems at the refinery. It was installed in 1968, in association with a refinery expansion program. It includes a John Zink burner, Model No. STF-S-30. This is an elevated flare, which is designated under Rule 1118 as a General Service Flare. It is equipped with natural gas fired pilots (3 pilots with a total flow rate of 150 scf/hr). Natural gas is also used as a purge gas in the flare. Vent gases processed by the flare are mostly low molecular weight, high hydrogen content, gases. The flare height is 161.25 ft. and the flare tip diameter is 2.5 ft. Steam is injected at the tip of the flare, through 33 steam jets, to assist with mixing of combustion gases. The capacity of the Hydrocracker Flare is a load of 417,000 lbs/hr @ Molecular Weight of 5.7 lb/lb-mole. Flare capacity is a function of several parameters including the maximum recommended tip velocity (manufacturer supplied) and the molecular weight of relieving gas. The Hydrocracker Flare System and the FCCU Flare System (Process 21, System 2) are interconnected so that each will serve a significant part of the refinery north area, when the other unit is shut down for service. The Hydrocracker Flare System is permitted to receive vent gas from the following equipment under normal operating conditions: Light Ends Depropanizer, Jet Fuel Hydrotreating Unit, Mid-Barrel Desulfurization Unit, Light Gasoline Hydrogenation Unit, Catalytic Reformer Units, Hydrogen Plant, Hydrocracking Units, LPG Recovery System, Liquid Petroleum Gas Drying Facilities, and MDEA Regeneration Systems. During shutdown of the FCCU Flare, the Hydrocracker Flare serves several additional units located in the north area of the refinery. Under this project the new PSV listed in the table below will be connected to a closed vent system, venting to the Hydrocracker Flare System.

Flare Connection	**PSV Number**	**System / Connection Description**
1	25PSV5024	No. 1 Light Hydrotreating Unit (P5S4); Stabilizer Product Coalescer (RW-7182)

The PSVs tied into the Hydrocracker Flare have multiple relieving cases, either in unique relief or as part of a common relief scenario. Common release scenarios, which impact flare size, are described in the table below.

Hydrocracker Flare General Common Release Scenarios

Common Release Scenarios	Lbs/hr	MW	Flare Tip Mach No.
Total Plant Wide Failure	258,452	13.4	0.362
Reaction Unit Major Fire	355,011	11.6	0.482
Fractionation Unit Major Fire	412,022	12.8	0.491
Compressor Failure	418,902	5.7	0.697

The flare tip velocities are within the manufacturer (John Zink) recommended limits stated below:

4. 0.7 Mach for processing hydrocarbons with some inert gases such as CO_2, steam, etc…
5. 0.8 Mach for processing straight hydrocarbons
6. 0.9 Mach for processing hydrocarbons with 50 mole % or more hydrogen

The vent gases from Compressor Failure are greater than 90% hydrogen, but for the other three general relief scenarios they are predominantly hydrocarbons. The Compressor Failure scenario results in a Mach No. of 0.697, which is below the recommended limit of 0.9. The highest Mach number associated with the other relief scenarios is 0.491, which is below the recommended limit of 0.8 for processing of hydrocarbons.

This evaluation includes the additional PSV tie-in the Hydrocracker Flare. The Hydrocracker Flare was selected to receive these vent gases for the following reasons:

- plant operators have the ability to coordinate the shutdown of the flare and the equipment which is vented to the flare,
- the PSV connection is in close proximity to Hydrocracker Flare headers,
- previous PSV tie-ins from this or similar equipment were to the Hydrocracker Flare,
- the Hydrocracker Flare system has sufficient capacity to handle vent gas from this connection.

The new PSV has the following failure scenario.

Flare Connection	PSV Number	Relief Scenario	Relief Load (lb/hr)	MW
1	25PSV5024	External Fire only on new RPV 7182	8,823	127.8

The highest flare tip velocity is Mach 0.09 for a release from 25PSV5024 (8,823 lbs/hr, MW =127.8) with simultaneous depressurizing from the No. 1 Light Hydrotreating Unit (68,000 lbs/hr, MW =13.8). This is well within the flare peak design case of Mach 0.8 from processing of hydrocarbons.

For this project Tesoro evaluated the tie-in (Attachment #6 A/N 575840) and has determined the following:

- The new PSV does not contribute to any of the common relief scenarios that impact flare size. Thus, it does not change the back pressures on existing PSV during any of the common failure scenarios.
- A release from 25PSV5024 is not the sizing basis for the flare capacity. There is no significant impact to the flare header when the PSV is tied to the closed system.
- The additional load to the Hydrocracker Flare from the new PSV tie-in from the No. 1 Light Hydrotreating Unit will not cause the capacity of the flare to be exceeded.

No. 5 Flare System

The No. 5 Flare System (also known as the Isom Flare) receives process gas and emergency vent gas from a variety of processes/systems at the refinery. It also receives a vent stream from the nearby facility - Ineos Polyropylene LLC (Facility ID: 124808). This is an elevated flare, which is designated under Rule 1118 as a General Service Flare. It includes a flare gas burner, Model 42” FHP. It is equipped with natural gas fired pilots (3 pilots with a total flow rate of 250 scf/hr). Natural gas is also used as purge gas in the flare. The flare height is 265 ft. and the flare tip diameter is 3.5 ft. Steam is injected at the tip of the flare to assist with mixing of combustion gases. The capacity of the No. 5 Flare is a load of 1,450,000 lbs/hr @ Molecular Weight of 35 lb/lb-mole. Flare capacity is a function of several parameters including the maximum recommended tip velocity (manufacturer supplied) and the molecular weight of relieving gas. It was constructed in 1994/1995 to serve new units (Naphtha HDS Unit, Naphtha HDS Reactor Feed Heater, Naphtha Isomerization Unit, C5 Alkylation Unit, C5 Alkylation Feed Treater Unit, and Hydrogen Plant) which were planned to meet the requirements of CARB Phase II Reformulated Gasoline.

The vent gas steam from Ineos Polypropylene LLC is generated during startup and shutdown of the polypropylene plant. This stream is inherently low in sulfur. However, it contains polypropylene fines which are incompatible with vapor recovery compressors and thus must bypass the flare gas recovery system and vent directly to the flare.

Under this project the new PSVs listed in the table below will be connected to a closed vent system, venting to the No. 5 Flare System.

Flare Connection	PSV Number	System / Connection Description
1	74PSV5007	LPG Railcar Loading/Unloading Rack (P14S11); new Knock Out Drum (RW-7186)
2	74PSV5008	LPG Railcar Loading/Unloading Rack (P14S11); New Vaporizer (RW-9009)
3	74PSV5009	LPG Railcar Loading/Unloading Rack (P14S11); Surge Drum (RW-7185)
4	74PSV5013	LPG Railcar Loading/Unloading Rack (P14S11); piping – propane truck loading header
5	74PSV5108	LPG Railcar Loading/Unloading Rack (P14S11); Odorant Storage Tank (D2139; RW 0056-289.02). Replacement of an existing PSV which is currently connected to flare.

6	76PSV5008	Alkylation Unit (P9S1); piping – propane line to the Alkylation Unit.
7	76PSV5009	Alkylation Unit (P9S1); piping – propylene line to the Alkylation Unit.
8	44PSV5045	Naphtha Hydrodesulfurization Unit (P5S5); Depentanizer Tower – RPV 941 (D637)
9	44PSV5043	Naphtha Hydrodesulfurization Unit (P5S5); Depentanizer Overhead Accumulator – RPV 942 (D656)
10	44PSV5046	Naphtha Hydrodesulfurization Unit (P5S5); Depentanizer Bottoms Surge Drum – RPV 955 (D658)
11	44PSV5042	Naphtha Hydrodesulfurization Unit (P5S5); Straight Run Naphtha Depentanizer Bottoms Cooler (RPV6420/6421)
12	44PSV5051	Naphtha Hydrodesulfurization Unit (P5S5); Straight Run Naphtha Depentanizer Overhead Product Cooler (RPV5359)

Notes: PSVs 44PSV-5043, 44PSV-5045, 44PSV-5046 replace atmospheric PSVs currently in service on these vessels

Odorant Storage Tank (D2139) is listed in the facility permit under Process 14: Loading and Unloading; System 12: Odorizing System Serving LPG Loading/Unloading Systems. As the new PSV replaces another PSV also connected to the flare system as there is no change in PSV size, this modification is exempt from permitting under 219(c)(3) (identical equipment replacement in whole or in part of any equipment where a permit to operate had previously been granted for such equipment) and no application for modification of Process 14, System 12 is required.

The PSVs tied into the No. 5 Flare have multiple relieving cases, either in unique relief or as part of a common relief scenario. Common release scenarios, which impact flare size, are described in the table below.

No. 5 Flare General Common Release Scenarios

Common Release Scenarios	Lbs/hr	MW	Flare Tip Mach No.
Total Refinery Power Failure	1,450,000	35	0.57
Refinery Cooling Water Failure (No. 8 Cooling Tower Failure)	364,005	30	0.15
Polypropylene Plant Power Failure	886,835	38	0.32
Fire (largest fire circle release – Unit 7600 Fire Circle A)	479,170	42	0.16

The new PSVs have the following failure scenarios.

Flare Connection	PSV Number	Relief Scenario	Relief Load (lb/hr)	MW
Naphtha Hydrodesulfurization Unit				
1	44PSV-5045	External Fire only	113,611	79.5
2	44PSV-5046	External Fire only	19,903	79.1
3	44PSV-5043	External Fire only	53,735	70.6
4	44PSV-5042	External Fire only	38,252	80.6
5	44PSV-5051	External Fire only	14,577	71.3
LPG Railcar Loading/Unloading Rack				
6	74PSV-5007	External Fire only	6,665	41.8
7	74PSV-5008	External Fire	3,998	41.8
		Block Discharge	11,729	42.3
8	74PSV-5009	External Fire only	44,564	41.8
9	74PSV-5013	Thermal Expansion only	119	SG = 0.5
10	74PSV-5108	External Fire only	9,590	62.1
Alkylation Unit				
11	76PSV-5008	Thermal Expansion only	147	SG = 0.5
12	76PSV-5009	Thermal Expansion only	116	SG = 0.5

For this project Tesoro evaluated the tie-ins (Attachment #6 A/N 575839) and has determined the following:

- The new PSVs do not contribute to any of the common relief scenarios that impact flare size. Thus, they do not change the back pressures on existing PSV during any of the common failure scenarios.
- The new PSVs serving the LPG Railcar Loading/Unloading Rack (Knock Out Drum (RW-7186); New Vaporizer (RW-9009); and Surge Drum (RW-7185)) contribute to the No. 42 Loading Rack (Unit 7442) Fire Circle release scenario. The additional relief load from the new PSVs results in an increase in back-pressure on an

	existing conventional type PSV - 74PSV5108, protecting Odorant Storage Tank (D2139; RW 0056-289.02). The resulting back-pressure is higher than what is allowable for a conventional type PSV. Therefore 74PSV5108 will be replaced with a balanced-bellows type PSV under this project. The relief load associated with 74PSV5108 will not change. • The combined loads and flare tip velocities due to releases from new PSVs to the No. 5 Flare System under this project are as follows: 1. Naphtha Hydrodesulfurization Unit 44PSV-5045/5046/5043 External Fire Scenario maximum fire relief load: 187,249 lbs/hr (Mach 0.05); 2. LPG Loading/Unloading Rack 74PSV-5007/5008/5009/5108 External Fire Scenario fire relief load: 64,817 lbs/hr (Mach 0.02); 3. LPG Loading/Unloading Rack 74PSV-5008 Block Discharge on new RW 9009: 11,729 lbs/hr, Mach 0.004. For these cases, the highest flare tip velocity is Mach 0.05, which is well below the peak design case of Mach 0.8 for hydrocarbon releases. • The additional load to the No. 5 Flare from the new PSV tie-ins from the Naphtha Hydrodesulfurization Unit, LPG Railcar Loading/Unloading Rack, and Alkylation unit will not cause the capacity of the flare to be exceeded. In addition to the permit changes described above, Tesoro has requested that condition D90.16 be eliminated from the permit. The No. 5 Flare System is now subject to the requirements of 40 CFR 60 Subpart Ja, which limits the H_2S concentration in fuel gas combusted in the flare and requires monitoring of H_2S concentration. The No. 5 Flare system is no longer subject to 40 CFR 60 Subpart J, or to the Alternative Monitoring Plan (AMP) issued to satisfy the requirements of this regulation.

EMISSIONS

For most of the subject permit units, this project results in an increase in Volatile Organic Compound (VOC) emissions due to increases in the fugitive components in the permit units. These emissions increases are quantified in tables below. The pre-project and post-project potential-to-emit of criteria pollutant emissions from the No. 51 Vacuum Distillation Unit Heater (D63), due to the increase in permit heat input rating from 300 MMBtu/hr to 360 MMBtu/hr, is also quantified below. Except for SO_x, the heater's emissions will not change as a result of this project as pollutant emissions limits will be retained and/or enacted in order to ensure there is no increase in the potential-to-emit. For the flare systems (South Area Flare System, Hydrocracker Flare System No. 5 Flare System), the connections of PSVs result in no increase in emissions from the flare systems as the changes in fugitive components associated with these modifications are accounted for under the processes/systems venting to the flare systems.

Process 1, System 5; No. 51 Vacuum Distillation Unit - Fugitive VOC Emissions Increase

New Source Unit		Service	Number of Components in Existing System	Net Number of Components Added/ Removed	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	88	+92	180	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	171	0	171	4.55	778.05	0	778.05
		Light Liquid	74	+24	98	4.55	336.70	+109.20	445.90
		Heavy Liquid	288	+165	453	4.55	1,310.40	+750.75	2,061.15
Pumps	Seal-less Type	Light Liquid	0	0	0	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	5	0	5	46.83	234.15	0	234.15
	Single Mechanical Seal	Heavy Liquid	9	+3	12	46.83	421.47	+140.49	561.96
Compressors		Gas/Vapor	0	0	0	9.09	0	0	0
Flanges		GasVapor/ Light Liquid	348	+36	384	6.99	2,432.52	+251.64	2,684.16
Connectors		GasVapor/ Light Liquid	570	+51	621	2.86	1,630.20	+145.86	1,776.06
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	19	0	19	9.09	172.71	0	172.71
Flanges		Heavy Liquid	465	+248	713	6.99	3,250.35	+1,733.52	4,983.87
Connectors		Heavy Liquid	761	+378	1,139	2.86	2,176.46	+1,081.08	3,257.54
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	25	+6	31	9.09	227.25	+54.54	281.79
Pressure Relief Valves		All	12	0	12	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	99	+2	101	9.09	899.91	+18.18	918.09
						Total Lbs/yr	13,870.17	+4,285.26	18,155.43
						Total Lbs/day	38.00 (38.53 lbs/day – 30 day avg.)	+11.74 (+11.90 lb/day 30 day avg.)	49.74 (50.43 lbs/day 30 day avg.)
						Total Lbs/hr	1.58	+0.49	2.07

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Process 5, System 2; Mid Barrel Desulfurizer Unit - Fugitive VOC Emissions

New Source Unit		Service	Number of Components in Existing System	Net Number of Components Added/ Removed	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	59	33	92	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	600	0	600	4.55	2,730.00	0	2,730.00
		Light Liquid	166	11	177	4.55	755.30	+50.05	805.35
		Heavy Liquid	832	0	832	4.55	3,785.60	0	3,785.60
Pumps	Seal-less Type	Light Liquid	0	11	11	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	3	0	3	46.83	140.49	0	140.49
	Single Mechanical Seal	Heavy Liquid	26	0	26	46.83	1,217.58	0	1,217.58
Compressors		Gas/Vapor	4	0	4	9.09	36.36	0	36.36
Flanges		GasVapor/ Light Liquid	761	51	812	6.99	5,319.39	+356.49	5,675.88
Connectors		GasVapor/ Light Liquid	2,275	63	2,338	2.86	6,506.50	+180.18	6,686.68
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	83	0	83	9.09	754.47	0	754.47
Flanges		Heavy Liquid	0	0	0	6.99	0	0	0
Connectors		Heavy Liquid	0	0	0	2.86	0	0	0
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	0	0	0	9.09	0	0	0
Pressure Relief Valves		All	21	0	21	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	74	0	74	9.09	672.66	0	672.66
						Total Lbs/yr	21,918.35	+586.72	22,505.07
						Total Lbs/day	60.05 (60.88 lbs/day – 30 day avg.)	+1.61 (+1.63 lb/day 30 day avg.)	61.66 (62.51 lbs/day 30 day avg.)
						Total Lbs/hr	2.50	+0.07	2.57

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Process 5, System 4; No. 1 Light Hydrotreating Unit - Fugitive VOC Emissions

New Source Unit		Service	Number of Components in Existing System	Net Number of Components Added/ Removed	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	114	123	237	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	173	23	196	4.55	787.15	104.65	891.80
		Light Liquid	334	195	529	4.55	1,519.70	887.25	2,406.95
		Heavy Liquid	0	0	0	4.55	0	0	0
Pumps	Seal-less Type	Light Liquid	0	0	0	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	2	0	2	46.83	93.66	0	93.66
	Single Mechanical Seal	Heavy Liquid	0	0	0	46.83	0	0	0
Compressors		Gas/Vapor	0	0	0	9.09	0	0	0
Flanges		GasVapor/ Light Liquid	703	409	1,112	6.99	4,913.97	2,858.91	7,772.88
Connectors		GasVapor/ Light Liquid	1,537	439	1,976	2.86	4,395.82	1,255.54	5,651.36
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	58	13	71	9.09	527.22	118.17	645.39
Flanges		Heavy Liquid	0	0	0	6.99	0	0	0
Connectors		Heavy Liquid	0	0	0	2.86	0	0	0
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	0	0	0	9.09	0	0	0
Pressure Relief Valves		All	7	4	11	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	7	1	8	9.09	63.63	9.09	72.72
						Total Lbs/yr	12,301.15	+5,233.61	17,534.76
						Total Lbs/day	33.70 (34.17 lbs/day – 30 day avg.)	+14.34 (+14.54 lb/day 30 day avg.)	48.04 (48.71 lbs/day 30 day avg.)
						Total Lbs/hr	1.40	+0.60	2.00

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Process 5, System 5; Naphtha Hydrodesulfurization Unit - Fugitive VOC Emissions

New Source Unit		Service	Number of Components in Existing System + Components Repurposed from the Iso-Octene Unit	Net Number of Components Added/ Removed	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	181	+100	281	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	140	+23	163	4.55	637.00	+104.65	741.65
		Light Liquid	327	+68	395	4.55	1,487.85	+309.40	1,797.25
		Heavy Liquid	0	0	0	4.55	0	0	0
Pumps	Seal-less Type	Light Liquid	0	0	0	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	9	0	9	46.83	421.47	0	421.47
	Single Mechanical Seal	Heavy Liquid	0	0	0	46.83	0	0	0
Compressors		Gas/Vapor	0	0	0	9.09	0	0	0
Flanges		GasVapor/ Light Liquid	672	+215	887	6.99	4,697.28	+1,502.85	6,200.13
Connectors		GasVapor/ Light Liquid	1,229	+242	1,471	2.86	3,514.94	+692.12	4,207.06
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	43	+19	62	9.09	390.87	+172.71	563.58
Flanges		Heavy Liquid	0	0	0	6.99	0	0	0
Connectors		Heavy Liquid	0	0	0	2.86	0	0	0
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	0	0	0	9.09	0	0	0
Pressure Relief Valves		All	3	+5	8	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	5	0	5	9.09	45.45	0	45.45
						Total Lbs/yr	11,194.86	+2,781.73	13,976.59
						Total Lbs/day	30.67 (31.10 lbs/day – 30 day avg.)	+7.62 (+7.73 lb/day 30 day avg.)	38.29 (38.82 lbs/day 30 day avg.)
						Total Lbs/hr	1.28	+0.32	1.60

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Process 8, System 2; Hydrocracker Unit–Fractionation Section-Fugitive VOC Emissions

New Source Unit		Service	Number of Components in Existing System	Net Number of Components Added/ Removed	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	172	0	172	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	434	0	434	4.55	1,974.70	0	1,974.70
		Light Liquid	610	0	610	4.55	2,775.50	0	2,775.50
		Heavy Liquid	256	+14	270	4.55	1,164.80	63.70	1,228.50
Pumps	Seal-less Type	Light Liquid	0	0	0	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	11	0	11	46.83	515.13	0	515.13
	Single Mechanical Seal	Heavy Liquid	8	0	8	46.83	374.64	0	374.64
Compressors		Gas/Vapor	3	0	3	9.09	27.27	0	27.27
Flanges		GasVapor/ Light Liquid	1,465	+18	1,483	6.99	10,240.35	+125.82	10,366.17
Connectors		GasVapor/ Light Liquid	4,532	+22	4,554	2.86	12,961.52	+62.92	13,024.44
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	116	0	116	9.09	1,054.44	0	1,054.44
Flanges		Heavy Liquid	266	0	266	6.99	1,859.34	0	1,859.34
Connectors		Heavy Liquid	824	0	824	2.86	2,356.64	0	2,356.64
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	21	0	21	9.09	190.89	0	190.89
Pressure Relief Valves		All	26	0	26	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	89	0	89	9.09	809.01	0	809.01
						Total Lbs/yr	36,304.23	+252.44	36,556.67
						Total Lbs/day	99.46 (100.85 lbs/day – 30 day avg.)	+0.69 (+0.70 lb/day 30 day avg.)	100.16 (101.55 lbs/day 30 day avg.)
						Total Lbs/hr	4.14	+0.03	4.17

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Process 9, System 1; Alkylation Unit - Fugitive VOC Emissions Increase

New Source Unit		Service	Number of Components in Existing System	Net Number of Components Added/ Removed	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	171	+192	363	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	355	83	438	4.55	1,615.25	+377.65	1,992.90
		Light Liquid	3,502	+167	3,669	4.55	15,934.10	+759.85	16,693.95
		Heavy Liquid	0	0	0	4.55	0	0	0
Pumps	Seal-less Type	Light Liquid	0	0	0	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	33	0	33	46.83	1,545.39	0	1,545.39
	Single Mechanical Seal	Heavy Liquid	0	0	0	46.83	0	0	0
Compressors		Gas/Vapor	1	0	1	9.09	9.09	0	9.09
Flanges		GasVapor/ Light Liquid	3,223	+565	3,788	6.99	22,528.77	+3,949.35	26,478.12
Connectors		GasVapor/ Light Liquid	8,099	+539	8,638	2.86	23,163.14	+1,541.54	24,704.68
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	272	+27	299	9.09	2,472.48	+245.43	2,717.91
Flanges		Heavy Liquid	0	0	0	6.99	0	0	0
Connectors		Heavy Liquid	0	0	0	2.86	0	0	0
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	0	0	0	9.09	0	0	0
Pressure Relief Valves		All	103	+6	109	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	237	+1	238	9.09	2,154.33	9.09	2,163.42

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

	Pre-modification	Change	Post-modification
Total Lbs/yr	69,422.55	+6,882.91	76,305.46
Total Lbs/day	190.20 (192.84 lbs/day – 30 day avg.)	+18.86 (+19.12 lb/day 30 day avg.)	209.06 (211.96 lbs/day 30 day avg.)
Total Lbs/hr	7.92	+0.79	8.71

Process 9, System 9; Iso-Octene Unit - Fugitive VOC Emissions Change

New Source Unit		Service	Number of Components in Existing System	Components Re-Purposed for use in NHDS P5S5 (shown as decrease)	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	92	-22	70	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	45	-39	6	4.55	204.75	-177.45	27.30
		Light Liquid	187	-90	97	4.55	850.85	-409.50	441.35
		Heavy Liquid	0	0	0	4.55	0	0	0
Pumps	Seal-less Type	Light Liquid	0	0	0	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	4	-4	0	46.83	187.32	-187.32	0
	Single Mechanical Seal	Heavy Liquid	0	0	0	46.83	0	0	0
Compressors		Gas/Vapor	0	0	0	9.09	0	0	0
Flanges		GasVapor/ Light Liquid	340	-158	182	6.99	2,376.60	-1,104.42	1,272.18
Connectors		GasVapor/ Light Liquid	434	-202	232	2.86	1,241.24	-577.72	663.52
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	15	-7	8	9.09	136.35	-63.63	72.72
Flanges		Heavy Liquid	0	0	0	6.99	0	0	0
Connectors		Heavy Liquid	0	0	0	2.86	0	0	0
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	0	0	0	9.09	0	0	0
Pressure Relief Valves		All	12	0	12	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	99	-5	94	9.09	899.91	-45.45	854.46
						Total Lbs/yr	5,897.02	-2,565.49	3,331.53
						Total Lbs/day	16.16 (16.38 lbs/day – 30 day avg.)	-7.03 (-7.13 lb/day 30 day avg.)	9.13 (9.25 lbs/day 30 day avg.)
						Total Lbs/hr	0.67	-0.29	0.38

Notes: The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

The counts associated with repurposing the Iso-Octene equipment represent existing fugitive components currently permitted under the Iso-Octene Unit (P9S9). As they are existing permitted fugitive component counts, there will be no change in emissions at the facility (neither emissions increases or decreases) resulting from the re-purposing of these existing fugitive components from the Iso-Octene Unit (P9S9) to the Naphtha Hydrodesulfurization Unit (P5S5).

Process 14, System 11; LPG Railcar Loading/Unloading Rack - Fugitive VOC Emissions Increase

New Source Unit		Service	Number of Components in Existing System	Net Number of Components Added/ Removed	Number of Components in Modified System	ROG Emissions Factor (lb/yr)	Pre-modification Annual Emissions (lbs/yr)	Change in Annual Emissions (lbs/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	94	+176	270	0.0	0	0	0
	SCAQMD Approved I & M Program	Gas/Vapor	0	+159	159	4.55	0	+723.45	723.45
		Light Liquid	238	+158	396	4.55	1,082.90	+718.90	1,801.80
		Heavy Liquid	0	0	0	4.55	0	0	0
Pumps	Seal-less Type	Light Liquid	0	0	0	0	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	0	3	3	46.83	0	+140.49	140.49
	Single Mechanical Seal	Heavy Liquid	0	0	0	46.83	0	0	0
Compressors		Gas/Vapor	0	0	0	9.09	0	0	0
Flanges		GasVapor/ Light Liquid	284	+761	1,045	6.99	1,985.16	+5,319.39	7,304.55
Connectors		GasVapor/ Light Liquid	708	+1,000	1,708	2.86	2,024.88	+2,860.00	4,884.88
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	9	+4	13	9.09	81.81	+36.36	118.17
Flanges		Heavy Liquid	0	0	0	6.99	0	0	0
Connectors		Heavy Liquid	0	0	0	2.86	0	0	0
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	0	0	0	9.09	0	0	0
Pressure Relief Valves		All	12	8	20	0	0	0	0
Process Drains with P-Trap and Seal Pot		All	0	0	0	9.09	0	0	0
						Total Lbs/yr	5,174.75	+9,798.59	14,973.34
						Total Lbs/day	14.18 (14.37 lbs/day – 30 day avg.)	+26.85 (+27.22 lb/day 30 day avg.)	41.02 (41.59 lbs/day 30 day avg.)
						Total Lbs/hr	0.59	+1.12	1.71

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Process 19, System 9; Refinery Interconnection System - Fugitive VOC Emissions

New Source Unit		Service	Number of Components in New System	ROG Emissions Factor (lb/yr)	Post-modification Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	143	0.0	0
	SCAQMD Approved I & M Program	Gas/Vapor	0	2.29	0
		Light Liquid	375	2.29	858.75
		Heavy Liquid	125	2.29	286.25
Pumps	Seal-less Type	Light Liquid	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	0	46.83	0
	Single Mechanical Seal	Heavy Liquid	0	46.83	0
Compressors		Gas/Vapor	0	9.09	0
Flanges		GasVapor/ Light Liquid	129	3.66	472.14
Connectors		GasVapor/ Light Liquid	812	1.46	1,185.52
Other (includes fittings, hatches, sight glasses, meters)		GasVapor/ Light Liquid	36	5.05	181.80
Flanges		Heavy Liquid	245	3.66	896.70
Connectors		Heavy Liquid	356	1.46	519.76
Other (includes fittings, hatches, sight glasses, meters)		Heavy Liquid	17	5.05	85.85
Pressure Relief Valves		All	39	0	0
Process Drains with P-Trap and Seal Pot		All	0	9.09	0
				Total Lbs/yr	4,486.77
				Total Lbs/day	12.29 (12.46 lbs/day – 30 day avg.)
				Total Lbs/hr	0.51

Note: The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals. **Emissions factors are based on a screening value of 200 ppm – except for rotating equipment (pumps and compressors) and process drains which are based on a screening value of 500 ppm**. In conjunction with this calculation, permit condition S31.X2 which is applied to P19S9, imposes a leak repair threshold of 200 ppm VOC for fugitive components, except for pumps, compressors and process drains for which a leak repair threshold of 500 ppm is stated. This screening value was proposed by Tesoro to limit the increase in the amount of non-attainment air contaminant emissions required to be offset.

Process 21, System 1: South Area Flare System – Fugitive VOC Component Counts/Emissions under A/N 553112

New Source Unit		Service	Number of Components in Process 21, System 1	ROG Emissions Factor (lb/yr)	Annual Emissions (lbs/yr) Process 21, System 1
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	214	0.0	0
	SCAQMD Approved I & M Program	Natural Gas	75	0.0	0
		Gas/Vapor	268	4.55	1,219.4
		Light Liquid	65	4.55	295.75
		Heavy Liquid	0	4.55	0
Pumps	Seal-less Type	Light Liquid	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	5	46.83	234.15
	Single Mechanical Seal	Heavy Liquid	0	46.83	0
Fittings (Flanges, connectors, & others)		All	1505	6.99	10,519.95
Process Drains with P-Trap and Seal Pot		All	8	9.09	72.72
PRVs		All	10	0	0
					Total Lbs/yr: 12,342
					Total Lbs/day: 33.81 (34.28 lbs/day – 30 day avg.)
					Total Lbs/hr: 1.41

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Criteria pollutant emissions entered in the District New Source Review (NSR) records under A/N 571391 for the South Area Flare System are shown in the table below. This project does not result in an increase in criteria pollutant emissions from the flare.

Criteria Pollutants Emissions–South Area Flare System; NSR Record under A/N 571391

	CO	ROG	NO_x	PM_{10}	SO_x
South Area Flare System	5,503.68 lbs/yr 15 lbs/day-30 day average 0.63 lbs/hr	13,278.72 lbs/yr 36.88 lbs/day-30 day average 1.52 lbs/hr	1,048.32 lbs/yr 3 lbs/day-30 day average 0.12 lbs/hr	394.44 lbs/yr 1 lbs/day-30 day average 0.04 lbs/hr	6,027.84 lbs/yr 17 lbs/day-30 day average 0.69 lbs/hr

Under this application, the NSR records for the South Area Flare System will be updated. This is required as the previous NSR records listed outdated combustion emissions from the South Area Flare System (calendar year 2005 estimated emissions with flare gas recovery in place for CO, NO_x, PM_{10} and SO_x). Updated emissions include emissions due to combustion of flare purge and pilot gas (natural gas) and VOC emissions from fugitive components. Updated flare emissions, which will be entered in the NSR records are shown in the table below.

Criteria Pollutants Emissions – South Area Flare System – Updated NSR Records

Emissions (lbs/day – 30 day average)	CO	ROG	NO_x	PM_{10}	SO_x
Purge Gas & Pilot Gas Combustion	*5.41*	*1.08*	*20.09*	*1.16*	*0.13*
Fugitives		*34.28*			
Total	*5.41*	*35.36*	*20.09*	*1.16*	*0.13*

Notes: Pilot Gas Flow (Total)=150 scf/hr; Purge #2 Gas Flow Rate= < 800 scf/hr; Purge #3 Gas Flow Rate= 5,400 scf/hr
ROG Emissions Factor = 7 lbs/MMscf; NO_x Emissions Factor = 130 lbs/MMscf; CO Emissions Factor = 35 lbs/MMscf; PM_{10} Emissions Factor = 7.5 lbs/MMscf; SO_x Emissions Factor = 0.83 lbs/MMscf
lbs/day – 30 day average is equal to annual emissions divided by 12 months per year and 30 days per month.

Process 21, System 3: Hydrocracker Flare System - Fugitive VOC Emissions/Components under A/N 511727

New Source Unit		Service	Number of Components in Existing System	ROG Emissions Factor (lb/yr)	Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	87	0.0	0.0
	SCAQMD Approved I & M Program	Natural Gas	28	4.55	127.4
		Gas/Vapor	84	4.55	382.2
		Light Liquid	21	4.55	95.6
		Heavy Liquid	0	4.55	0
Pumps	Seal-less Type	Light Liquid	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	3	46.83	140.5
	Single Mechanical Seal	Heavy Liquid	0	46.83	0
Compressors		Gas/Vapor	0	9.09	0
Flanges and Connectors		All	445	6.99	3,110.6
Pressure Relief Valves		All	2	0	0
Process Drains with P-Trap and Seal Pot		All	0	9.09	0
				Total Lbs/yr	3,856.2
				Total Lbs/day	10.56 (10.71 lbs/day – 30 day avg.)
				Total Lbs/hr	0.44

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

For the Hydrocracker Flare, combustion emissions as found in the evaluation under A/N 511727, are tabulated below. This project does not result in an increase in criteria pollutant emissions from the flare.

Potential-to-Emit of Combustion Contaminants from Hydrocracker Flare

	CO	ROG	NO_x	PM_{10}	SO_x
Hydrocracker Flare System Combustion Emissions	23,156 lbs/yr 64 lbs/day-30 day average 2.64 lbs/hr	4,081 lbs/yr 11 lbs/day-30 day average 0.47 lbs/hr	4,700 lbs/yr 13 lbs/day-30 day average 0.54 lbs/hr	2,164 lbs/yr 6 lbs/day-30 day average 0.25 lbs/hr	27,420 lbs/yr 76 lbs/day-30 day average 3.13 lbs/hr

Under this application, the NSR records for the Hydrocracker Flare System will be updated. This is required as the previous NSR records listed outdated combustion emissions from the Hydrocracker Flare System (Year 2004/2005 AER emissions with flare gas recovery in place). Updated emissions include emissions from combustion of flare purge and pilot gas (natural gas) and VOC emissions from fugitive components. Updated flare emissions, which will be entered in the NSR records are shown in the table below.

Criteria Pollutants Emissions – Hydrocracker Flare System – Updated NSR Records

Emissions (lbs/day – 30 day average)	CO	ROG	NO_x	PM_{10}	SO_x
Purge Gas & Pilot Gas Combustion	*3.02*	*0.60*	*11.23*	*0.65*	*0.07*
Fugitives		*10.71*			
Total	*3.02*	*11.31*	*11.23*	*0.65*	*0.07*

Notes: Pilot Gas Flow (total)= 150 scf/hr; Purge #2 Gas Flow Rate= < 800 scf/hr; Purge #3 Gas Flow Rate= 2,600 scf/hr
ROG Emissions Factor = 7 lbs/MMscf; NO_x Emissions Factor = 130 lbs/MMscf; CO Emissions Factor = 35 lbs/MMscf; PM_{10} Emissions Factor = 7.5 lbs/MMscf; SO_x Emissions Factor = 0.83 lbs/MMscf
lbs/day – 30 day average is equal to annual emissions divided by 12 months per year and 30 days per month.

Process 21, System 6: No. 5 Flare System - Fugitive VOC Emissions/Components revised under A/N 553120

New Source Unit		Service	Number of Components in Existing System	ROG Emissions Factor (lb/yr)	Annual Emissions (lbs/yr)
Valves	Sealed Bellows	Gas/Vapor and Light Liquid	214	0.0	0.0
	SCAQMD Approved I & M Program	Natural Gas	77	0.0	0.0
		Gas/Vapor	156	4.55	709.80
		Light Liquid	88	4.55	400.40
		Heavy Liquid	0	4.55	0
Pumps	Seal-less Type	Light Liquid	0	0	0
	Double Mechanical Seals or Equivalent Seals	Light Liquid	5	46.83	234.15
	Single Mechanical Seal	Heavy Liquid	0	46.83	0
Compressors		Gas/Vapor	0	9.09	0
Flanges and Connectors		All	1184	6.99	8,276.16
Pressure Relief Valves		All	1	0	0
Process Drains with P-Trap and Seal Pot		All	8	9.09	72.72
				Total Lbs/yr	9,693.23
				Total Lbs/day	26.56 (26.92 lbs/day – 30 day avg.)
				Total Lbs/hr	1.11

The emission factors are derived using CAPCOA Revised 1995 EPA Correlation Equations and Factors for Refineries and Marketing Terminals and are based on a screening value of 500 ppmv.

Criteria pollutant emissions entered in the NSR records under A/N 553120 for the No. 5 Flare are shown in the table below. This project does not result in an increase in criteria pollutant emissions from the flare.

Criteria Pollutants Emissions – No. 5 Flare System – NSR Record under A/N 553120

	CO	ROG	NO_x	PM_{10}	SO_x
No. 5 Flare System	10,832.54 lbs/yr 30 lbs/day-30 day average 1.24 lbs/hr	6,988.80 lbs/yr 19 lbs/day-30 day average 0.80 lbs/hr	2,795.52 lbs/yr 8 lbs/day-30 day average 0.32 lbs/hr	698.88 lbs/yr 2 lbs/day-30 day average 0.08 lbs/hr	349.44 lbs/yr 1 lbs/day-30 day average 0.04 lbs/hr

Under this application, the NSR records for the No. 5 Flare System will be updated. This is required as the previous NSR records listed outdated combustion emissions from the No. 5 Flare System (Year 2005 emissions data for CO, NO_x, PM_{10} and SO_x). Updated emissions include emissions from combustion of flare purge and pilot gas (natural gas) and emissions of VOC emissions from fugitive components. Updated flare emissions, which will be entered in the NSR records are shown in the table below.

Criteria Pollutants Emissions – No. 5 Flare System – Updated NSR Records

Emissions (lbs/day – 30 day average)	CO	ROG	NO_x	PM_{10}	SO_x
Purge Gas & Pilot Gas Combustion	*3.45*	*0.69*	*12.81*	*0.74*	*0.08*
Fugitives		*26.92*			
Total	*3.45*	*27.61*	*12.81*	*0.74*	*0.08*

Notes: Pilot Gas Flow (total) = 250 scf/hr; Purge #2 Gas Flow Rate= < 800 scf/hr; Purge #3 Gas Flow Rate= 3,000 scf/hr
ROG Emissions Factor = 7 lbs/MMscf; NO_x Emissions Factor = 130 lbs/MMscf; CO Emissions Factor = 35 lbs/MMscf; PM_{10} Emissions Factor = 7.5 lbs/MMscf; SO_x Emissions Factor = 0.83 lbs/MMscf
lbs/day – 30 day average is equal to annual emissions divided by 12 months per year and 30 days per month.

No. 51 Vacuum Distillation Unit Heater (D63) Potential-to-Emit

Under A/N 567649, the permit heat input rating of the No. 51 Vacuum Distillation Unit Heater (D63) will increase from 300 MMBtu/hr to 360 MMBtu/hr. The Potential-to-Emit of criteria pollutants at the current and higher firing rate is shown in the table below.

The heater specifications from the equipment supplier (Brown & Root Braun) stated the following for the burners, "The burners shall be sized for 120 percent of the design full load heat release and combustion air quantities, based on a draft of 0.1 inches water column at the arch level." Thus, the re-rating of the heater requires no physical modification of the equipment.

NO_x & SO_x Emissions

Tesoro has proposed to accept emission limits such that the project will be evaluated under Reg. XIII and Rule 2005 as one with no associated increase in criteria pollutant emissions. The project results in no increase in NO_x emissions and thus does not trigger requirements under Rule 2005, as the following permit limit will be implemented: NO_x = 2.62 lbs/hr (potential-to-emit of NO_x emissions, equal to the hourly maximum in the previous 12 months of operation). This ensures that there is no NO_x increase, as under Rule 2005 an emissions increase is defined as the post-modification maximum hourly potential-to-emit minus the potential-to-emit immediately prior to proposed modification. Attachment #5 (A/N 567649) has hourly NO_x emissions, fuel input, and heat input over the period of two years, prior to application submittal. SO_x emissions from equipment exclusively firing natural gas is exempt from Regulation XX. Thus, there are no requirements under Rule 2005 for the SO_x emissions from this heater.

The new NO_x limit is based on 12 months data prior to the application deemed complete date of April 14, 2015. However, ammonia valve position data indicate that abnormally low levels of ammonia were injected into the SCR from the period of August 11, 2014 (8:00 AM) through the remainder of the data set (April 13, 2015). Therefore, these data are not representative of controlled emissions for determination of the maximum NO_x level. Using the period from April 14, 2014 to August 11, 2014 (8:00 AM), the maximum measured NO_x concentration was 7.18 ppm (on July 29, 2014 at 9:00 AM). The hourly NO_x mass emissions rate at this NO_x concentration level, at the pre-project maximum firing rate is calculated below.

NO_x Emissions = 7.18 ppm NO_x x 46 lbs/lb-mole x 300 MMBtu/hr x 8710 dscf/MMBtu x 20.9% / 10^6 ppm x 385.3 cf/lb-mole x (20.9% - 3)

NO_x Emissions = 2.62 lbs/hr (assuming heater operates at O2 concentration of 3%)

CO, ROG, and PM Emissions

The current permit limits for CO, ROG and PM, stated under permit condition A63.30, are: 21 lbs CO/day, 36 lbs ROG/day, and 106 lbs PM/day. These emissions limits, which were calculated in the original permitting of the heater (A/N 174076), are based on outdated emissions factors of 21 lbs PM/MMscf and 4.1 lbs CO/MMscf and a fuel higher heating value (1350 Btu/scf), which is appropriate for firing refinery fuel gas, not natural gas. However, the emissions factor used for ROG (7 lbs/MMscf) is still currently valid. Under this evaluation it is proposed to update the emissions limits to those calculated using currently valid emissions factors (7.5 lbs PM/MMscf, 7 lbs ROG/MMscf, and 35 lbs CO/MMscf) and an appropriate higher heating value for natural gas combustion of 1050 Btu/scf. Using these factors, the following emissions rates/limits are calculated.

	Pollutant		
Pre-Modification Potential-to-Emit	PM	ROG	CO
Emissions Factor, lbs/MMscf	7.5	7	35
Emissions, lbs/day – 30 day average @ 300 MMBtu/hr	52.14	48.67	243.33

Thus, the current pollutant limits under condition A63.30 will be updated to the daily pre-project potential-to-emit shown in the table above. This project is not expected to result in an increase in emissions of these criteria pollutants, thus these mass emissions rates will be retained in the permit as the post-modification potential-to-emit.

	Pollutant		
Post-Modification Potential-to-Emit	PM	ROG	CO
Emissions, lbs/day – 30 day average @ 360 MMBtu/hr	52.14	48.67	243.33
Emissions Rate, lbs/MMscf @ 360 MMBtu/hr	6.3	5.9	29.6

The emissions rates for PM, ROG and CO at 360 MMBtu/hr, calculated above, will also be retained in the permit (under Emissions and Requirements) to ensure that emissions remain below the pre-project potential-to-emit.

No. 51 Vacuum Distillation Unit Heater (D63) Potential-to-Emit of Criteria Pollutants

Pollutant	Emissions Factor	Pre-Project PTE at 300 MMBtu/hr)	Post-Project PTE at 360 MMBtu/hr)	Emissions Change
NO_x Emissions	Basis: maximum hourly potential to emit immediately prior to the proposed modification	2.62 lbs/hr 62.88 lbs/day 63.75 lbs/day – 30 day average	No Change to Pre-Project Emission Limit	No Change
SO_x Emissions	0.6 lbs/MMscf	0.17 lbs/hr 4.11 lbs/day 4.17 lbs/day – 30 day average	0.21 lbs/hr 4.94 lbs/day 5.01 lbs/day – 30 day average	+0.03 lbs/hr +0.82 lbs/day +0.83 lbs/day – 30 day average
PM Emissions	Pre-Project & Post-Project: 7.5 lbs/MMscf	2.14 lbs/hr 51.43 lbs/day 52.14 lbs/day – 30 day average	No Change to Pre-Project Emission Limit	No Change
CO Emissions	Pre-Project & Post-Project: 35 lbs/MMscf	10.00 lbs/hr 240.00 lbs/day 243.33 lbs/day – 30 day average	No Change to Pre-Project Emission Limit	No Change
ROG Emissions	Pre-Project & Post-Project: 7 lbs/MMscf	2.00 lbs/hr 48.00 lbs/day 48.67 lbs/day – 30 day average	No Change to Pre-Project Emission Limit	No Change

Notes:
1. Natural gas heating value = 1050 Btu/scf
2. SO_x emissions factor is the AER default emissions factor for external combustion of natural gas – other equipment
3. Lbs/day – 30 day average is equal to annual emissions (hourly emissions x 8760 hrs/yr) divided by 12 months per year, divided by 30 days per month.
4. In the EIR post-project potential-to-emit of NO_x is calculated as:

NO_x Emissions = 9 ppm NO_x x 46 lbs/lb-mole x 360 MMBtu/hr x 8710 dscf/MMBtu x 20.9% x 24 hrs/day / 10^6 ppm x 385.3 cf/lb-mole x (20.9% - 3%)

NO_x Emissions = 94.41 lbs/day

The shutdown of the FCCU and associated heaters at the Tesoro LAR Wilmington Operations facility will result in a decrease in VOC emissions. This emissions reduction is shown below. It is calculated based on the procedure prescribed in the January 20, 2005 Rule Implementation Guidance memorandum entitled "Determining Net Emission Decreases for Concurrent Facility Modifications." This guideline specifies the use Rule 1306(d)(2) for calculating emissions decrease, for equipment permitted under the District New Source Review (NSR) program. Under this section an emissions decrease is calculated as the post modification potential-to-emit minus the permitted or allowable pre-modification potential-to-emit. For the Tesoro LAR Wilmington Operations FCCU the post-modification potential-to-emit is equal to 0 lbs/day for all criteria pollutants, as the equipment will be taken out of service. The pre-modification potential-to-emit is equal to the data entry in the NSR program under the current (most recent) application. However, the heaters associated with the FCCU (H-2 Heater (D92), H-3 Heater (D89), H-4 Heater (D90), H-5 Heater (D91), FCCU Startup Heater (D1664), and CO Boiler (D112)), were never permitted under the District NSR program. For this equipment emissions reductions are calculated as actual emissions over the past two years, reduced to the amount which would be actual if current Best Available Control Technology (BACT) were applied. Attachment #1 contains the calculations for emissions reductions from the heaters, based on current BACT emissions factors.

VOC Emissions Change from Shutdown of FCCU and Associated Heaters at Tesoro Wilmington Operations (based on NSR entry for FCCU Regenerator and BACT adjusted actual emissions reductions for the heaters):

	FCCU Regenerator lbs/day	**Heaters lbs/day**	**Total lbs/day**
Volatile Organic Compounds	-125.00	-18.87	-143.87

The VOC emissions reduction exceeds the expected emissions increases from this set of equipment modifications at Tesoro LAR Carson Operations, which are tabulated below.

Emissions Change Due to Current Modifications for Tesoro Carson Operations:

A/N 567643	No. 51 Vacuum Distillation Unit	VOC = +11.90 lbs/day – 30 day avg.
A/N 567645	No. 1 Light Hydrotreating Unit	VOC = +14.54 lbs/day – 30 day avg.
A/N 567646	Naphtha HDS Unit	VOC = +7.73 lbs/day – 30 day avg.
A/N 567647	Alkylation Unit	VOC = +19.12 lbs/day – 30 day avg.
A/N 567648	LPG Railcar Loading/Unloading Rack	VOC = +27.22 lbs/day – 30 day avg.
A/N 575837	Refinery Interconnection System	VOC = +12.46 lbs/day – 30 day avg.
A/N 578248	Mid Barrel Desulfurizer Unit	VOC = +1.63 lbs/day – 30 day avg.
A/N 578249	Hydrocracker – Fractionation Section	VOC = +0.70 lbs/day – 30 day avg.
Total Emissions Change		VOC = +95.30 lbs/day – 30 day avg.

The project results in increased emissions of Toxic Air Contaminants (TACs) from the subject process units. These are calculated, based on the increases in fugitive VOC emissions and the service type of fugitive components (gas/vapor, light liquid, heavy liquid). TAC emissions increases are tabulated below. (Note: Tesoro has not sought to use the contemporaneous risk reduction exemption under District Rule 1401, for decreases in TAC emissions from removal of equipment from service.)

No. 51 Vacuum Distillation Unit

Pollutant	Emissions Increase (lbs/yr)
Benzene (including benzene from gasoline)	0.034187
Cresol (mixture)	0.296570
Ethyl benzene	0.619635
Naphthalene	2.452899
Phenol	0.347423
Toluene (methyl benzene)	0.662368
Xylenes (isomers and mixtures)	2.709210

Mid Barrel Desulfurizer

Pollutant	Emissions Increase (lbs/yr)
1,2,4-Trimethylbenzene	3.726845
2,2,4-Trimethylpentane	0.106783
Benzene (including benzene from gasoline)	7.635574
Cresols (mixtures of cresylic acid)	0.011734
Cumene	0.113824
Cyclohexane	27.80290
Ethylbenzene	3.717458
Naphthalene	0.018188
n-Hexane	18.04164
Phenol	0.011734
Toluene	11.487391
Xylenes (mixed)	12.802817

Note: Utilized total VOC emissions increase of 586.72 lbs/yr (Light Liquid TAC Stream RS108).

No. 1 Light Hydrotreating Unit

Pollutant	Emissions Increase (lbs/yr)
Butadiene, 1, 3-	0.012041
Ammonia	0.000521
Benzene (including benzene from gasoline)	5.396621
Hydrogen Sulfide	102.3184
Hexane (n-)	8.24255
Propylene	0.723225
Toluene (methyl benzene)	254.889
Xylenes (isomers and mixtures)	15.63984

Naphtha Hydrodesulfurization Unit

Pollutant	Emissions Increase (lbs/yr)
Butadiene, 1, 3-	0.012087
Ammonia	0.000523
Benzene (including benzene from gasoline)	2.768101
Hydrogen Sulfide	53.56529
Hexane (n-)	4.689664
Propylene	0.725894
Toluene (methyl benzene)	130.7734

Note: Utilized updated total VOC emissions increase of 2,781.73 lbs/yr. The TAC emissions are calculated from Light Liquid VOC emissions increase of 2,677.08 lbs/yr (TAC Stream RS120) and Gas Vapor VOC emissions increase of 104.65 lbs/yr (TAC Stream RS004). TAC stream speciation profiles found in Attachment #3.

Hydrocracker Unit – Fractionation Section

Pollutant	Emissions Increase (lbs/yr)
1,2,4-Trimethylbenzene	1.57606
Cresols (mixtures of cresylic acid)	0.01262
Cumene	0.01262
Ethylbenzene	0.187639
Naphthalene	9.231731
Phenanthrene	0.005806
Phenol	0.012622
Toluene	0.066467
Xylenes (mixed)	1.300899

Note: Utilized total VOC emissions increase of 252.44 lbs/yr (TAC Stream RS203). TAC stream speciation profiles found in Attachment #3.

Alkylation Unit

Pollutant	Emissions Increase (lbs/yr)
Butadiene, 1, 3-	0.306394
Benzene (including benzene from gasoline)	0.017620
Hydrogen Sulfide	2.072617
Hexane (n-)	0.100907
Propylene	5.541941
Toluene (methyl benzene)	0.520431

Note: Utilized updated total VOC emissions increase of 6,882.68 lbs/yr. The TAC emissions are calculated from Light Liquid VOC emissions increase of 6,505.39 lbs/yr (TAC Stream RS030RS099RS123) and Gas Vapor VOC emissions increase of 377.30 lbs/yr (TAC Stream RS006RS030). TAC stream speciation profiles found in Attachment #3.

LPG Railcar Loading/Unloading Rack

Pollutant	Emissions Increase (lbs/yr)
Benzene (including benzene from gasoline)	0.456022
Hexane (n-)	0.423449
Butadiene, 1,3-	7.817521
Propylene	7899.061
Hydrogen Sulfide	3.113598

Refinery Interconnection System

Pollutant	Emissions Increase (lbs/yr)
Butadiene, 1,3-	4.788569
Benzene (including benzene from gasoline)	22.27561
Cresol mixtures	0.223664
Ethyl benzene	32.35331
Hydrogen sulfide	0.001345
Methanol (methyl alcohol)	0.015895
Naphthalene	4.688644
Hexane (n-)	35.52017
Phenol	0.134410
Propylene	2174.443
Toluene (methyl benzene)	194.0404
Xylenes (isomers and mixtures)	129.8559

No. 51 Vacuum Distillation Unit Heater (D63)

Pollutant	Emissions Factor (lb/MMSCF)	Emissions Increase (lb/hr)	Emissions Increase (lb/year)
Benzene	0.0017	9.71E-5	0.850
Formaldehyde	0.0036	2.06E-4	1.801
PAH's	0.0004	2.28E-5	0.200
Naphthalene	0.0003	1.71E-5	0.150
Acetaldehyde	0.0009	5.14E-5	0.450
Acrolein	0.0008	4.57E-5	0.400
Propylene	0.01553	8.87E-4	7.768
Toluene	0.0078	4.45E-4	3.902
Xylenes	0.0058	3.31E-4	2.901
Ethylbenzene	0.0020	1.14E-4	1.000
Hexane	0.0013	7.42E-5	0.650

Notes: TAC emissions are calculated based on an increase in firing rate from 300 MMBtu/hr to 360 MMBtu/hr. Based on an HHV of 1050 Btu/hr increased fuel flow is 0.0571 MMSCF/hr.
Emissions factors are provided by the Ventura County Air Pollution Control District for natural gas external combustion equipment.

Attachment #3 in each application folder contains the Rule 1401 Screening Health Risk Assessment (HRA) for each process unit, based on the TAC emissions increases tabulated above. For each process unit modification a Tier I/II Screening HRA was performed. For the Refinery Interconnection System a Tier IV HRA was also performed. For all process units except the No. 51 Vacuum Distillation Unit Heater, TAC increases are based on the increase in total VOC emissions from fugitive components and the service type (vapor, light liquid, heavy liquid). The calculations utilized a database for TAC mass fractions for each process stream, which was compiled from various sources including analytical data, Material Safety Data Sheets (MSDS), and engineering estimates based on process knowledge. Attachment #3 also contains a description of the calculation methodology employed as well as the TAC profiles for refinery process streams.

RULE EVALUATION

California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA), Public Resources Code Section 21000 et seq., requires that environmental impacts of proposed "projects" be evaluated and that feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects be identified and implemented. The Los Angeles Refinery Integration and Compliance (LARIC) Project qualifies as a Significant Project, therefore, preparation of a CEQA document is required. The District is the lead agency in this analysis and has the principal responsibility for carrying out and approving the project. The draft Environmental Impact Report (EIR) for the "Tesoro Los Angeles Refinery Integration and Compliance Project" is expected to be circulated for public comment in February, 2016 and to be certified by the District after receipt of public comments.

The final EIR will be certified prior to the issuance of any of the Permits to Construct. The permits will be issued with a condition (S11.X1) which requires compliance with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which will be part of the SCAQMD Certified Final EIR.

Rule 212 - Standards for Approving Permits and Issuing Public Notice

Public noticing will be required for this project for the following reason(s):

212(c)(1): This section requires public noticing for a new or modified permit unit, if it is within 1000 feet from of the outer boundary of a school. The subject equipment is not within 1000 feet of a school boundary.

212(c)(2): This section requires noticing for a new or modified facility which has an on-site emissions increase exceeding any of the daily maxima specified in §212(g), as listed below:

Volatile Organic Compounds	30 lbs/day
Nitrogen Dioxide	40 lbs/day
PM_{10}	30 lbs/day
Sulfur Dioxide	60 lbs/day
Carbon Monoxide	220 lbs/day
Lead	3 lbs/day

The addition of new equipment and modification of existing equipment under the LARIC Project at Tesoro LAR Wilmington and Carson Operations results in an increase in VOC of greater than 30 lbs/day. Therefore, public noticing is triggered under this section.

212(c)(3): This section requires public noticing for any new or modified permit unit, if the project results in an increase in emissions of Toxic Air Contaminants (TAC)s such that a person may be exposed to Maximum Individual Cancer Risk (MICR) greater than or equal to 1 in a million ($1x10^{-6}$) during a lifetime of 70 years. This section also requires public noticing if it is determined that the equipment will result in exposure to substances which pose a potential risk of nuisance. The Tier II Screening Health Risk Assessments (HRAs) prepared for each permit unit, as well as a Tier IV HRA prepared for the Refinery Interconnection System, indicate that the increase in MICR associated with each process unit modification is less than 1 in a million. Therefore, public noticing is not required based on the standards of this section.

212(d): This section states the requirements for distribution of the public notice. For projects in which a public notice is required due to an emissions increase exceeding daily maxima stated under 212(g) or where a person may be exposed to a MICR exceeding one in a million, the applicant shall be responsible for distribution of the public notice to each address within a ¼ mile of the project. For projects in which the public notice is required due to new or modified equipment which may emit air contaminants and which are located within 1000 feet of the outer boundary of a school, the public notice shall be distributed to parents or legal guardians of children in any school within ¼ mile of the facility and to each address within a radius of 1000 feet from the outer property line of the facility.

212(g): This section lists daily pollutant emissions rates above which pubic noticing is triggered. It also describes public notice content and dissemination requirements. These include a District analysis of the effect on air quality to be viewed at one location in the affected area, prominent advertisement in the affected area, and mailing of the notice to the US EPA, the affected state, and local government agencies. A 30 day period shall be maintained for submittal/receipt of public comments. Public noticing for this project will be carried out to meet the requirements stated under this section.

Rule 401 – Visible Emissions

This rule requires that a source not emit visible emissions with a shade as dark as or darker than that which has been designated Ringelmann No. 1, by the US Bureau of Mines, for a period exceeding three minutes in any hour. The subject equipment and permit modifications are not expected to result in an increase in visible emissions. Condition D323.1 requires bi-weekly inspection of the flares for visible emissions and corrective action to achieve compliance with this rule. Continued compliance with this rule is expected.

Rule 402 - Nuisance

With proper operation and maintenance, the subject equipment is not expected to be a source of public nuisance. Equipment modifications will be required to meet BACT standards, thus minimizing emissions of nuisance pollutants. The LPG Railcar Loading/Unloading Rack vents to the refinery vapor recovery system during loading operations and thus is expected to operate without emitting nuisance odors to the atmosphere. In addition, the project involves connection of PSVs to closed systems venting to flares, thus controlling emissions from any release event. Continued compliance with the requirements of this rule is expected.

Rule 404 – Particulate Matter – Concentration This rule limits the concentration of particulate matter emitted from a source. The particulate matter concentration limit is proportional to the volumetric flow rate of vent gas discharged, with a maximum concentration of 0.196 grains/cubic foot. The No. 51 Vacuum Distillation Unit Heater (D63) is subject to the requirements of this rule. The Tesoro LARIC

Project, which includes an increase of the permit heat input rating of the No. 51 Vacuum Distillation Unit Heater (D63), has no potential to increase particulate matter emissions as the daily PM limit for the heater will be maintained at 52.14 lbs/day. Continued compliance with the requirements of this rule is expected.

Rule 407 – Liquid and Gaseous Air Contaminants

This rule states limits of 2000 ppm CO (by volume on a dry basis averaged over 15 minutes) and 500 ppm SO_2 (averaged over 15 minutes) from a source. The No. 51 Vacuum Distillation Unit Heater (D63) is subject to the CO concentration limit of this rule. Under this project, the permit heat input rating of No. 51 Vacuum Distillation Unit Heater (D63) will be increased from 300 MMBtu/hr to 360 MMBtu/hr. However, this permit limit change involves no physical modification of equipment. The daily CO limit for the heater of 243.33 lbs/day will be maintained. The heater is limited to firing natural gas and thus will emit SO_2 at a concentration of less than 10 ppm. The Flare Systems, which meet the standards under 40 CFR 60 Subpart A and utilizing steam to enhance mixing of combustion gases, are expected to emit less than 2000 ppm CO. Continued compliance with the requirements of this rule is expected.

Rule 409 – Combustion Contaminants

This rule limits particulate matter emissions from combustion sources to 0.1 grains per cubic foot (corrected to 12% CO_2 and averaged over 15 minutes). The No. 51 Vacuum Distillation Unit Heater (Device ID: D63) is subject to the requirement of this rule. Under this project, the permit heat input rating of No. 51 Vacuum Distillation Unit Heater (D63) will be increased from 300 MMBtu/hr to 360 MMBtu/hr. However, this permit limit change involves no physical modification of equipment. The daily PM limit of the heater of 52.14 lbs/day will be maintained. In addition, as this unit exclusively fires natural gas, emissions of particulate matter from the heater are minimized. The modification/addition of other equipment is not expected to result in any increase in particulate matter emissions. Continued compliance with the requirements of this rule is expected.

Rule 431.1 – Sulfur Content of Gaseous Fuels

This rule limits the sulfur content of natural gas used in a facility to 16 ppm, calculated as H_2S. The natural gas combusted in the No. 51 Vacuum Distillation Unit Heater (D63) and utilized as pilot/purge gas in the flares is from a utility regulated by the California Public Utilities Commissions and is expected to meet this sulfur content limitation. Natural Gas at this site is supplied by the Southern California Gas Company, which is expected to have a sulfur content of no more than 0.75 grains S/100 scf, corresponding to a sulfur concentration of 12 ppm sulfur as H_2S. However, over the long term the sulfur content of natural gas fired at this facility is not expected to exceed 0.29 grains/100 scf. Continued compliance with the requirements of this rule is expected.

Rule 462 – Organic Liquid Loading

The purpose of this regulation is to limit VOC emissions from facilities which load organic liquids having a vapor pressure of 1.5 psia or greater under actual loading conditions, into tank truck, trailer, or railroad tank car. As stated under 462(b)(11), Liquefied Petroleum Gas (LPG) does not meet the definition of "organic liquid" under this rule. Therefore, the LGP Railcar Loading/Unloading Rack is not subject to the requirements of this rule.

Rule 465 – Refinery Vacuum-Producing Devices or Systems

The purpose of this rule is to limit emissions of VOCs and sulfur compounds from vacuum-producing devices or systems. It requires that exhaust gases from vacuum-producing devices or systems be continuously collected and added to a fuel gas system or combustion device, which has been issued a permit by the District. The ejectors serving the No. 51 Vacuum Distillation Unit are subject to the requirement of this rule. Under permit condition S18.7 the Coker Blowdown Gas Compression System (Process 2, System 6) is permitted to receive, recover and/or dispose of vent gases from the No. 51 Vacuum Distillation Unit. Continued compliance with this rule is expected.

Reg. IX - New Source Performance Standards

In some cases the processes/systems to be modified or newly constructed under the Tesoro LARIC Project result in increases in VOC emissions. Where processes/systems have an associated emissions increase, the equipment is deemed to undergo "modification," as defined under 40 CFR 60.14. For the processes/systems to be modified (No. 51 Vacuum Distillation Unit, Mid Barrel Desulfurizer Unit, No. 1 Light Hydrotreating Unit, Naphtha Hydrodesulfurization Unit, Hydrocracker Unit – Fractionation Section, Alkylation Unit, LPG Railcar Loading/Unloading Rack, Refinery Interconnection System), the project triggers applicability of additional New Source Performance Standards (NSPS) requirements, as promulgated under 40 CFR 60 Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

The South Area Flare System, Hydrocracker Flare System and No. 5 Flare System are subject to requirements under 40 CFR 60 Subpart A. Standards include: that the flare be operated without visible emissions (except for a period not to exceed 5 minutes during any 2 consecutive hours), that the flare be operated with a flame present at all times, that the flare gas meet maximum tip velocity and HHV standards (for steam assisted flares – heating value of greater than 300 Btu/scf, maximum exit velocity of 60 feet per second, or between 60 feet per second and 400 feet per second when the HHV of vent gas combusted exceeds 1000 Btu/scf), that it be monitored and maintained in conformance with its design, and that it be operated at all times when emissions may be vented to it. The South Area Flare System, Hydrocracker Flare System, and No. 5 Flare System will continue to be operated within their smokeless capacities; the flares are equipped with natural gas fired pilots which are continuously monitored; the flares will continue to be operated according to their design; and the flare gas heating value, total sulfur content, and flow rate will continue to be monitored according to the requirements of District Rule 1118. The connections of PSVs to the South Area Flare System, Hydrocracker Flare System and No. 5 Flare System does not affect compliance with the requirements of this regulation. Continued compliance with these standards is expected.

Regulation 40 CFR 60 Subpart Ja states standards for petroleum refineries for which construction, reconstruction, or modification occurred after May 14, 2007. For flares, however, an applicability date of June 24, 2008 is stated (i.e. the regulation applies to flares which were constructed, reconstructed, or modified after this date). Section 40CFR60.100a(c) defines a modification of a flare as when any new piping from a refinery process unit is connected to a flare (e.g. for direct emergency relief or some form of continuous or intermittent venting). Requirements include:

- The facility is required to develop and implement a written flare management plan. However, as allowed under 60.103a(g), the owner of a flare in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with paragraphs (a) through (e) of §60.103a. The owner of the flare must submit the existing flare management plan to the Administrator and must notify the Administrator that the flare is in compliance with SCAQMD Rule 1118.
- A compliance date of November 11, 2015, or the date of startup of the modified flare (whichever is later), is stated for the modified flare.
- The combustion of a fuel gas containing H_2S in excess of 162 ppmv, determined hourly on a 3 hour rolling average basis, is prohibited. Exemptions to this limitation include process upset gas or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction.
- The owner or operator is required to install, operate, calibrate and maintain an instrument for continuous monitoring and recording of the H_2S concentration (dry basis) in the fuel gas being burned in the flare. This system must be

maintained in accordance with Performance Specification 7 of Appendix B to Part 60.

- An affected flare in the SCAQMD may comply with the monitoring requirements under SCAQMD Rule 1118 as an alternative to requirements for flow monitoring and for the determination of total reduced sulfur in each gas line directed to the flare, stated under this regulation.

The PSV connections to the Hydrocracker Flare System and No. 5 Flare System will result in tagging of these flare systems with condition H23.39, indicating that they are subject to the requirements under 40 CFR 60 Subpart Ja. These flare systems and the South Area Flare System are expected to operate in compliance with these requirements and with the requirements under District Rule 1118.

Permit condition H23.3 requires fugitive VOC components in the systems modified under this project, to meet standards promulgated under 40CFR60 Subpart GGG. Tesoro LAR Carson Operations has applied the standards under this regulation on a facility-wide basis. This regulation requires that fugitive components meet standards stated in Sections 60.482-1 through 60.482-10, as soon as practicable, or within 180 days of equipment startup. The fugitive components in the subject processes/systems have been operated, monitored, and repaired according to the standards of this regulation and have been included in the facility's Rule 1173 Inspection and Maintenance (I&M) Program, which in general is more stringent than the requirements of this regulation. As proposed by Tesoro, the fugitive components in the No. 51 Vacuum Distillation Unit, Mid Barrel Desulfurizer Unit, No. 1 Light Hydrotreating Unit, Naphtha Hydrodesulfurization Unit, Hydrocracker Unit – Fractionation Section, Alkylation Unit, LPG Rail Car Loading/Unloading Rack and Refinery Interconnection System will be required to meet standards under 40 CFR 60 Subpart GGGa. Thus, after modification, the requirements of 40CFR60 Subpart GGG will no longer apply to these process units.

As this project involves construction of piping and fugitive components and results in an increase in VOC emissions, Tesoro plans to apply the standards under 40 CFR 60 Subpart GGGa to the subject equipment (No. 51 Vacuum Distillation Unit, Mid Barrel Desulfurizer Unit, No. 1 Light Hydrotreating Unit, Naphtha Hydrodesulfurization Unit, Hydrocracker Unit – Fractionation Section, Alkylation Unit, LPG Railcar Loading/Unloading Rack, Refinery Interconnection System). The regulation states VOC leak standards for "Process Units," which are defined as components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. While the Refinery Interconnection System does not meet the definition of "Process Unit" under this regulation, Tesoro has agreed to accept applicability of this regulation to the Refinery Interconnection

System. This regulation requires compliance with the standards under §40CFR60.482-1a through §40CFR60.482-10a, as soon as practicable, as but no later than 180 days after initial startup. It is expected that new and existing components in the subject systems will be operated in compliance with this regulation.

The standards stated under 40 CFR 60 Subpart QQQ apply to petroleum wastewater systems which have been constructed, modified, or re-constructed after May 4, 1987. Requirements are stated for drain components and oil-water separators. Permit condition S31.1, which states standards considered to be Best Available Control Technology (BACT) and is applicable to modifications of the No. 1 Light Hydrotreating Unit (Process 5, System 4) and the Alkylation Unit (Process 9, System 1), requires that all process drains be equipped with water seal, or a closed vent system and control device complying with the requirements of 40CFR60 Subpart QQQ Section 60.692-5. Further, condition S31.X1 requires new process drains installed under the LARIC Project to be equipped with similar controls. Compliance with these requirements is expected.

Reg. X – National Emission Standards for Hazardous Air Pollutants

The subject equipment includes Effluent Flash Tank (D406), Stabilizer Overhead Accumulator (D408), and Stripper Overhead Accumulator (D1424) which are subject to the National Emission Standard for Benzene Waste Operations, promulgated under 40 CFR 61 Subpart FF. Under this regulation these devices are classified as Oil Water Separators, and are required to meet standards under 40 CFR 61.347(a) and (b). This section requires that an Oil Water Separator be equipped with fixed cover and closed vent system which routes all organic vapors to a control device. The fixed cover shall operate with no detectable VOC emissions as determined by an instrument reading less than 500 ppm VOC, above background. Annual testing for VOC emissions (above background) and quarterly visual inspections of equipment are required. The closed vent system and control device are required to be in compliance with standards under §61.349. As an alternative to standards stated under §61.347, an Oil Water Separator may be equipped with a floating roof, or other control device, meeting the requirements under §61.352. Continued compliance with these standards is expected.

Under this evaluation the tagging of the Hydrocracker Area Flare System and No. 5 Flare System with condition H23.12, which show applicability of the National Emission Standard for Benzene Waste Operations promulgated under 40 CFR 61 Subpart FF, is eliminated. Previously, the Hydrocracker Flare System and No. 5 Flare System were classified as "Control Devices" under this regulation. However, an evaluation of the equipment at this facility used to comply with this regulation and the provisions of the regulation (below), indicates that the Hydrocracker Flare System and No. 5 Flare System are not subject to its provisions.

- The Tesoro LAR Carson Operations refinery operates an Oil Water Treating (Benzene NESHAP) System (Process 15, System 7) which treats oily water for compliance with 40 CFR 61 Subpart FF standards. This system has two Stripper Columns (D1644 and D1645) which are each designated as a "Treatment Process" under this regulation. Per Rule 1118, flaring is only allowed for Emergencies, Startups, Shutdowns, Turnarounds or Essential Operational Needs. In addition, Tesoro LAR Carson Operations operates a Flare Gas Vapor Recovery System which recovers gases and prevents flaring under most scenarios. Tesoro now indicates that "flaring rarely occurs except during emergencies or process upsets." Thus, the Hydrocracker Flare System and No. 5 Flare System do not function as "Control Devices" for benzene waste produced at this site.

Rule 1118 – Control of Emissions from Refinery Flares

This rule requires monitoring and recording of data associated with refinery flares and to minimize flaring and flare related emissions. The requirements include maintaining a pilot flame in the flare at all times; operating the flare in a smokeless manner except for a period of five minutes in any two consecutive hours; conducting annual surveys of pressure relief devices connected to a flare and repairing leaking devices no later than the following turnaround; conducting a specific cause analysis for any flaring event with emissions exceeding 100 lbs VOC, 500 lbs sulfur dioxide, or 500,000 scf of vent gas combusted; and conducting an analysis to determine the relative cause of any flaring event where more than 5,000 scf of vent gas are combusted. All flares must be operated to minimize flaring and no vent gas may be combusted except during emergencies, startups, shutdowns, turnarounds or essential operational needs. Tesoro has installed a flare gas recovery and treatment system, to achieve compliance with the requirements of this rule. The operator must prevent the combustion in a flare of vent gas with a hydrogen sulfide content exceeding 160 ppm, averaged over 3 hours, except for vent gas resulting from an emergency, startup, shutdown, process upset or pressure relief valve leakage. Beginning calendar year 2012, a refinery is required to limit sulfur dioxide emissions from flares to less than 0.5 tons per million barrel of crude processing capacity, calculated as an average over one calendar year (or prepare and submit to the District a Flare Minimization Plan and pay a mitigation fee, if exceeding the target emissions). Submittal to the District of a Flare Monitoring and Recording Plan is also required. The monitoring required for a General Service Flare include gas flow rate (in scfm) measured and recorded continuously with flow meters with or without on/off flow indicator; gas higher heating value (gross heating value in Btu/scf) continuously measured and recorded with a higher heating value analyzer; and total sulfur concentration (in ppm SO_2) semi-continuously measured and recorded with a total sulfur analyzer. It is expected that the South Area Flare System, Hydrocracker Flare System, and No. 5 Flare System will continue to operate in compliance with the requirements of this rule and in accordance with Tesoro's Flare Monitoring and Recording Plan approved under A/N 553129.

Rule 1146 - Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters

This rule applies to boilers, steam generators, and process heaters of 5 MMBtu/hr or greater heat input capacity that are used in industrial, institutional, or commercial operations. However, process heaters at petroleum refineries with a heat input rating of greater than 40 MMBtu/hr are exempt from the requirements of this rule. Therefore, the No. 51 Vacuum Distillation Unit Heater (D63) is exempt from its requirements.

Rule 1173 – Fugitive Emissions of Volatile Organic Compounds

This rule specifies leak control, identification, operation, inspection, maintenance, and recordkeeping requirements for all components in VOC service. The new and existing fugitives components of the subject equipment (No. 51 Vacuum Distillation Unit, Mid Barrel Desulfurizer Unit, No. 1 Light Hydrotreating Unit, Naphtha Hydrodesulfurization Unit, Hydrocracker Unit – Fractionation Section, Alkylation Unit, LPG Railcar Loading/Unloading Rack, Refinery Interconnection System) are/will be included in the facility's Inspection and Maintenance (I&M) Program and are expected to comply with rule requirements. This rule exempts components which are operated under negative pressure and components handling fluids which have a VOC content of less than 10% by weight. Continued compliance with these requirements is expected.

Reg. XIII - New Source Review

This rule states requirements including that projects meet standards considered to be Best Available Control Technology (BACT), that emissions offsets be provided for increases in non-attainment air contaminant emissions, and that air quality modeling be performed to assess the impacts of the project on ambient air quality.

BACT

With the exception of the Hydrocracker Unit – Fractionation Section and Iso-Octene Unit, the modifications of all process systems (No. 51 Vacuum Distillation Unit, Mid Barrel Desulfurizer Unit, No. 1 Light Hydrotreating Unit, Naphtha Hydrodesulfurization Unit, Alkylation Unit, LPG Railcar Loading/Unloading Rack, and Refinery Interconnection System) involve increases in VOC emissions of greater than 1.0 lb/day. Thus, the modifications must meet BACT standards, including use of bellows seal valves (unless meeting District exemption criteria). Permit conditions

S31.X1 and S31.X2 state BACT standards for fugitive components. The equipment modifications are expected to comply with these standards. Under this project all new PSVs in VOC service will be connected to a closed system (flare system, process piping, or relief recovery system); the project does not result in addition of any new atmospheric PSVs in VOC service. As the proposed increase in heat input limit for the No. 51 Vacuum Distillation Unit Heater (D63) does not result in an increase of any critieria pollutant of 1.0 lb/day or greater, BACT does not apply to this equipment.

Offsets

An exemption from offset requirement is allowed under Rule 1304(c)(2), for a Concurrent Facility Modification. The Concurrent Facility Modification must result in a net emissions decrease, as determined by Rule 1306. Further, the emissions reduction must occur after the date of submittal of an application for a permit to construct a new or modified source, but before the start of operation of the source. Thus, the shutdown of the LAR Wilmington Operations FCCU and associated heaters will result in an overall decrease in VOC emissions and emissions offsets for VOC emissions increases are not required for modification/addition of the No. 51 Vacuum Distillation Unit, Naphtha Hydrodesulfurization Unit, Alkylation Unit, LPG Railcar Loading/Unloading Rack, and Refinery Interconnection System. However, Tesoro plans to provide Emissions Reduction Credits (ERCs) to offset the emission increase associated with the modifications of the No. 1 Light Hydrotreating Unit, Mid Barrel Desulfurizer Unit, and Hydrocracker Unit – Fractionation Section. The modification of these units must be completed early to accommodate EPA Tier 3 gasoline compliance and/or scheduled turnarounds. Thus, the timing of startup of these modified units will not coincide with retirement of the Wilmington Operations FCCU and associated heaters. Using an offset ratio of 1.2, ERCs accounting for 20.24 lbs ROG/day (1.2 x 16.87 lbs/day) are required. The applicant must hold these ERCs in their account prior to issuance of the Permit to Construct. The facility currently holds ERCs for 323 lbs ROG/day (ERC Certificate No. AQ013063 - 172 lbs ROG/day; ERC Certificate No. AQ013064 - 50 lbs ROG/day; ERC Certificate No. AQ013066 - 3 lbs ROG/day; ERC Certificate No. AQ013677 - 4 lbs ROG/day; ERC Certificate No. AQ013741 - 89 lbs ROG/day; and ERC Certificate No. AQ013910 - 5 lbs ROG/day).

As SO_x is a precursor for the formation of particulate matter, ERCs are required for the SO_x increase from the No. 51 Vacuum Distillation Unit Heater (D63). Using an offset ratio of 1.2, ERCs accounting for 1.00 lbs SO_x/day (1.2 x 0.83 lbs/day) are required. The facility currently holds ERCs for 2 lbs SO_x/day (ERC Certificate No. AQ013067 - 2 lbs SO_x/day).

Per 1303(b)(3), a facility in zone 1 may only obtain Emissions Reduction Credits originating in zone 1. Tesoro LAR Carson Operations is in zone 1 and thus must obtain any additional ERCs from facilities in zone 1.

As allowed under Rule 1313(d), a maximum of ninety days shall be allowed for the startup and simultaneous operation of a new source or a modified source and the existing source it is intending to replace. This ninety day period is stated in permit condition L341.X1.

Statewide Compliance
As the increase of ROG of 1 lb/day or greater involves a Major Modification at an existing facility under Reg XIII, the facility is required to certify that all major stationary sources owned by Tesoro in the State of California are in compliance or on a schedule for compliance with all applicable emissions limitations and standards under the Clean Air Act. Attachment #7 contains Tesoro's certification that all major stationary sources in California are in compliance or on a schedule for compliance with the Clean Air Act.

Modeling
Air quality modeling does not apply to increases in VOC and SO_x emissions.

Compliance with the standards of this regulation is expected.

Rule 1401 – New Source Review of Carcinogenic Air Contaminants
This rule states requirements including that the increase in TAC emissions from a project not result in a Maximum Individual Cancer Risk (MICR) at any receptor location exceeding one in a million ($1x10^{-6}$) if T-BACT is not used, or ten in a million ($10x10^{-6}$) if T-BACT is employed, that Acute and Chronic Hazard Indices not exceed 1.0 for any target organ system at any receptor location, and that the cancer burden not exceed 0.5. Tier II Screening Health Risk Assessments (HRAs) have been prepared for each permit unit whose construction/modification results in increases in TAC emissions. In each case, the increase in MICR for the nearest residences and off-site workers are less than $1x10^{-6}$ and the Hazard Indices for each target organ system are below 1.0. The screening HRAs are found in Attachment #3 in each application folder. HRA results are summarized in the table below.

Tier II HRA Results for Tesoro LARIC Project Modifications

Equipment	Maximum Individual Cancer Risk (MICR)		Hazard Index Acute	Hazard Index Chronic
	Nearest Resident	Nearest Offsite Worker		
No. 51 Vacuum Distillation Unit	5.22E-09	1.61E-08	< 1.0 for all target organ systems	< 1.0 for all target organ systems
Mid Barrel Desulfurizer Unit	3.20E-08	4.41E-08		
No. 1 Light Hydrotreating Unit	1.85E-08	4.03E-08		
Naphtha Hydrodesulfurization Unit	4.88E-09	2.49E-08		
Hydrocracker Unit – Fractionation Section	4.61E-08	4.68E-08		
Alkylation Unit	3.19E-09	8.71E-09		
LPG Railcar Loading/Unloading	8.94E-08	3.82E-07		
Refinery Interconnection System	1.02E-07	7.75E-07		
No. 51 Vacuum Distillation Unit Heater (D63)	3.37E-07	1.05E-07		

These results indicate that the project is in compliance with Rule 1401 limits.

For the Refinery Interconnection System at LAR Carson Operations a Tier IV HRA was prepared in addition to the Tier II HRA. The Tier IV analysis assumes that emissions from the Refinery Interconnection System are distributed among the pigging station and other main interconnect piping installation locations. This was done in order to be consistent with the HRA performed in the CEQA analysis. The HRA was performed based on the current SCAQMD guidelines for preparing health risk assessments (South Coast Air Quality Management District, Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics "Hot Spots" Information and Assessment Act, June 5, 2015). The current guideline requires use of an updated version of the software, HARP[2] - Air Dispersion & Risk Tool, version 15197. Consistent with SCAQMD modeling guidelines, the AMS/EPA Regulatory Model (AERMOD, v15181) was used as the air dispersion model. HRA results are summarized in the table below. These results were reviewed by SCAQMD staff and accepted in a memorandum dated February 23, 2016 (see Attachment #3 under A/N 575837). The SCAQMD staff review found that the air dispersion analysis and HRA generally conform to SCAQMD's air dispersion and HRA methodologies.

Tier IV HRA Results for Tesoro LARIC Project Refinery Interconnection System – Tesoro LAR Carson Operations

Modeling Case	Increased Cancer Risk	Chronic Hazard Index	8-Hour Chronic Hazard Index	Acute Hazard Index
Residential Receptor	0.05×10^{-6}	0.0001	0.0001	0.0001
Offsite Workplace Receptor	0.26×10^{-6}	0.006	0.006	0.0019
Sensitive Receptor	0.04×10^{-6}	0.0001	0.0001	0.0001
Significance Threshold	**10×10^{-6}**	**1.0**	**1.0**	**1.0**
Significant	**No**	**No**	**No**	**No**

As the permit unit is subject to T-BACT, the cancer risk threshold for the permit unit is 10 in a million. The health risks from the permit unit were demonstrated to be less than Rule 1401 cancer and non-cancer permit limits of 10 in a million and hazard index of 1, respectively.

In the Environmental Impact Report (EIR) for the proposed project, an HRA was performed to determine if emissions of TACs generated by the LARIC Project, as a whole would exceed SCAQMD significance thresholds for cancer risk and hazard indices. The carcinogenic and non-carcinogenic impacts for all off-site receptors can be found in Appendix C of the EIR.

Reg XVII – Prevention of Significant Deterioration

The federal Prevention of Significant Deterioration (PSD) program has been established to protect air quality in those areas which already meet the primary National Ambient Air Quality Standards (NAAQS). This regulation sets forth pre-construction review requirements for stationary sources to ensure that air quality in clean air areas does not significantly deteriorate while maintaining a margin for future industrial growth. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new or modified emission sources that are classified as major stationary sources.

The South Coast Air Basin (SCAB) has been in attainment for NO_2, SO_2 and CO. Effective 7/26/13, the SCAB has been re-designated to "attainment area" for the 24 hour average PM_{10} NAAQS. Therefore, the regulation is applicable to these pollutants. The South Coast Air Basin is designated as non-attainment for VOC, which is a precursor for ozone, and $PM_{2.5}$ (particulate matter with an aerodynamic diameter of less than 2.5 micron). As the subject equipment emits PSD pollutants (NO_2, SO_2, CO and PM_{10}), it is subject to the requirements of this rule.

On 7/25/07, the EPA and SCAQMD signed a "Partial PSD Delegation Agreement". The agreement delegates the authority and responsibility to the District for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not set forth in SCAQMD Regulation XVII. The partial delegation agreement did not delegate authority and responsibility to SCAQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21. Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40 CFR Part 52 Subpart 21, or apply to the SCAQMD in accordance with the current requirements of Regulation XVII.

Tesoro has prepared a PSD applicability analysis for the LARIC project in accordance with the provisions of 40 CFR §52.21, as it utilizes "netting" procedure - i.e. contemporaneous emissions reductions from removal of equipment from service, to ensure that project emissions remain below PSD significance thresholds. This analysis considers emissions from both Tesoro Wilmington Operations and Tesoro Carson Operations. The PSD applicability determination has been submitted to EPA for review. The final determination is pending; issuance of permits for this project is contingent on the EPA's determination.

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases

This rule sets forth preconstruction review requirements for Greenhouse Gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714. The provisions of this rule shall apply to any source and the owner or operator of any source subject to any GHG requirements under 40 Code of Federal Regulations Part 52.21 as incorporated into this rule. The rule specifies what portions of 40 CFR, Part 52.21 do not apply to GHG emissions, which are identified in Rule 1714(c)(1) as exclusions. A PSD permit is required, prior to actual construction, of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively.

The proposed project does not trigger PSD for any pollutant and there is no increase in emissions. Therefore, the requirements of this rule are not applicable.

Reg. XX - Regional Clean Air Incentives Market (RECLAIM)

This facility is subject to RECLAIM requirements. The No. 51 Vacuum Distillation Unit Heater (D63) is a Major NO_x source and is therefore required to be monitored by a Continuous Emissions Monitoring System (CEMS). Data from the CEMS are transmitted daily to the SCAQMD. The CEMS are certified semi-annually or annually. As the modification of the No. 51 Vacuum Distillation Unit Heater (D63) does not result in an increase in NO_x emissions, RECLAIM New Source Review (NSR) requirements under Rule 2005, including: applicability of BACT standards, performing air quality modeling to ensure the project does not result in a significant increase in NO_2 concentration, and demonstrating that the facility holds sufficient RECLAIM Trading Credits (RTC)s to offset an emissions increase in the first year of operation at a 1:1 ratio, do not apply. SO_x emissions from equipment exclusively firing natural gas are exempt from Reg XX requirements. Under §2011(i) and §2012(k), monitoring, reporting and recordkeeping for NO_x and SO_x is not required for gas flares. Therefore, these rules do not apply to the flare systems. Continued compliance with the requirements of this rule is expected.

Reg. XXX - Title V Operating Permits

The Tesoro LAR Carson Operations facility is subject to Reg XXX and an initial Title V permit was issued to the previous site operator, BP West Coast Products LLC, on September 1, 2009. After the change of ownership on June 1, 2013, the Title V permit was transferred to new operator, Tesoro Refining & Marketing Co LLC, Tesoro LAR Carson Operations on July 12, 2013. Tesoro's Title V permit was renewed on January 29, 2016, under A/N 561341. Since the Tesoro LARIC Project involves modifications of existing equipment, that trigger applicability of a New Source Performance Standard (NSPS) pursuant to 40 CFR 60 (applicability of 40 CFR 60 Subpart GGGa), it is considered a Significant Revision of the Title V permit, under Rule 3000. As a Significant Revision, the applications are subject to the requirements for a 30 day public notice and a 45 day EPA review and comment period.

Rule 3006 addresses public notice requirements. It requires that a public notice be published in a newspaper serving the county where the source is located, or that a notice be sent by mail to those who request in writing to be on a list, and any other means as determined by the Executive Officer to ensure adequate notice to the affected public. This rule requires that the notice contain the following:

i) The identity and location of the affected facility;
ii) The name and mailing address of the facility's contact person;
iii) The identity and address of the South Coast Air Quality Management District as the permitting authority processing the permit;
iv) The activity or activities involved in the permit action;

v) The emissions change involved in any permit revision;
vi) The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer which are relevant to the permit decision;
vii) A brief description of the public comment procedure; and,
viii) The time and place of any proposed permit hearing which may be held, or a statement of the procedure to request a proposed permit hearing if one has not already been requested.

The SCAQMD plans to meet all public notice and EPA review and comment requirements for this project. Compliance with this regulation is expected.

40 CFR 63, Subpart CC

This regulation is applicable to facilities which are major sources of Hazardous Air Pollutants (HAPs), defined as those with a potential-to-emit of 10 tons per year for a single HAP or potential-to-emit of 25 tons per year for a combination of HAPs. Section 63.11 states requirements for control devices used to comply with applicable subparts of this regulation. For flares requirements include:

- flares are to be steam-assisted, air-assisted, or non-assisted,
- flares are to be operated at all times when emissions may be vented to them,
- flares are to be designed for and operated with no visible emissions, except for a total of 5 minutes in any two consecutive hour period,
- flares are to be operated with a flame present at all times. The presence of a flame is to be determined by a thermocouple or other equivalent device to detect the presence of a flame,
- the net heating value of gas combusted in a steam-assisted or air-assisted flare must be 300 Btu/scf or greater,
- steam-assisted or air-assisted flares are to be designed for and operated with an exit velocity of less than 60 ft/sec (or between 60 ft/sec and 400 ft/sec if the gas combusted has a net heating value of greater than 1000 Btu/scf).

The South Area Flare, Hydrocracker Flare System, and No. 5 Flare System are expected to continue to operate in compliance with these standards.

As specified in the "Emissions and Requirements" column, fugitive components of the subject process units are subject to this regulation. Continued compliance with standards for equipment leaks, stated under 40 CFR 60 Subpart VV, as referenced in 40 CFR 63.648, is expected.

Under this regulation (40 CFR 63 Subpart CC), the Disulfide Separator Vessel (D2372) is designated as a Group 2 Emissions Point (Miscellaneous Process Vent, Storage Vessel, or Wastewater Stream). A Group 2 Miscellaneous Process Vent is defined as a vent not meeting the criteria of Group 1 Miscellaneous Process Vent (total organic HAP concentration of 20 ppmv or greater, total VOC emissions of greater than 33 kg/day for existing sources and 6.8 kg/day for new sources at the outlet of the final recovery device, prior to any control device and prior to discharge to the atmosphere). A Group 2 Miscellaneous Process Vent is not required to meet any control standards and has no monitoring requirements. The regulation specifies test methods for TOC mass flow rate to demonstrate that it is below the threshold for classification as a Group 1 Miscellaneous Process Vent. The operator is required to recalculate TOC mass flow rate whenever there are process changes to determine whether the vent is in Group 1 or Group 2. Continued compliance with these requirements is expected.

40 CFR 64 - Compliance Assurance Monitoring

CAM is applicable to an emissions unit at a Title V facility which is: subject to an emissions limitation or standard, uses a control device to achieve compliance with the emissions limitation or standard, and has a potential-to-emit exceeding or meeting the Title V major source threshold for the pollutant. CAM requirements do not apply to this project, as it meets one or more of the following exemption criteria:

- The equipment does not use a control device to comply with emission limitation or standard (as required under §64.2(a)(2)).
- Pre-control emissions from the equipment are below the major source threshold (as required under §64.2(a)(3)).
- The equipment meets the exemption under §64.2(b)(i), in that the emission limitation or standard was proposed by the Administrator after November 15, 1990.
- The equipment meets the exemption under §64.2(b)(vi), in that the emissions limitation or standard specifies a continuous compliance determination method.

The equipment to be modified (No. 51 Vacuum Distillation Unit, Mid Barrel Desulfurizer Unit, No. 1 Light Hydrotreating Unit, Naphtha Hydrodesulfurization Unit, Hydrocracker Unit – Fractionation Section, Alkylation Unit, LPG Railcar Loading/Unloading Rack, Refinery Interconnection System) emit VOCs from fugitive components. However, no control devices are used to comply with emissions limitations for VOC emissions from fugitive components. Thus, CAM does not apply to the subject equipment.

Under this project, a NO_x emissions limit will be applied to the permit for the No. 51 Vacuum Distillation Unit Heater (D63). NO_x emissions from the heater are controlled by a Selective Catalytic Reduction (SCR) unit. However, as a RECLAIM Major Source, the heater is equipped with a NO_x CEMS, for continuous emissions determination. Thus, CAM does not apply to the subject equipment.

RECOMMENDATION:

Issue the Permits to Construct with the following conditions:

S11.X1 The operator shall comply with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which is part of the AQMD Certified Final Environmental Impact Report dated March xx, 2016 for this facility.

This condition shall only apply to equipment listed in Section H of this facility permit.

[CA PRC CEQA, 11-23-1970]

[Systems subject to this condition: Process 1, System 5, 8; Process 5, System 2, 4 , 5; Process 8, System 2; Process 9, System 1, 9; Process 14, System 11; Process 21, System 1, 3, 6]

S13.2 All devices under this system are subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1123

[**RULE 1123, 12-7-1990**]

[Systems subject to this condition: Process 1, System 5, 6; Process 5, System 2, 4, 5; Process 8, System 2; Process 9, System 1, 9]

S15.6 The vent gases from all affected devices of this process/system shall be vented as follows:

All sour gases shall be directed to amine contactor system located within this system.

This process/system shall not be operated unless the amine contactor system is in full use and has a valid permit to receive vent gases from this system.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 5, System 2, 4; Process 8, System 2]

S15.31 The vent gases from all affected devices of this process/system shall be vented as follows:

All waste gases generated from this system shall be directed to a thermal oxidizer or fuel gas combustion device which is in full use, has a valid permit to receive vent gases from this system, and complies with all applicable rules and regulations including 40CFR60, Subpart J limits and monitoring requirements.

All waste gas generated from this system shall be considered as fuel gas as defined in 40CFR60, Subpart J. Therefore, the vent gases are, when directed to a thermal oxidizer or fuel gas combustion device, subject to the H2S limits of Subpart J.

[**40CFR 60 Subpart J, 6-24-2008**]

[Systems subject to this condition: Process 9, System 1]

S31.X1 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 567643, 567645, 567646, 567647, 567648, 578248:

All new valves in VOC service shall be bellows seal valves except: (1) those specifically exempted by Rule 1173; (2) those in heavy liquid service as defined in Rule 1173; or (3) those approved by the District in the following applications: control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where valve failure could pose safety hazard (e.g., drain valves with valve stems in horizontal position), retrofits/special applications with space limitations, and valves not commercially available.

All new components in VOC service as defined by Rule 1173, except those specifically exempted by Rule 1173, shall be distinctly identified from other components through their tag numbers (e.g., numbers ending in the letter "N5"), and shall be noted in the records.

All new open-ended lines shall be equipped with cap, blind flange, plug, or a second valve.

All new pressure relief valves shall be connected to closed vent system or equipped with a rupture disc.

All new pumps shall utilize double seals and be connected to a closed vent system.

All new compressors shall be equipped with a seal system with a higher pressure barrier fluid.

All new process drains shall be equipped with water seal, or a closed vent system and control device complying with the requirements of 40CFR60 Subpart QQQ Section 60.692-5.

All new valves and flanges in VOC service as defined by Rule 1173, except those specifically exempted by the rule, shall be inspected monthly using EPA Method 21.

If 98.0 percent or greater of the new non-bellows seal valves and the new flanges population inspected (as an aggregate) is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv for two consecutive months, then the operator may change leak inspection interval for these components from monthly to quarterly with prior approval of the Executive Officer. The operator shall revert back to monthly inspection interval if less than 98.0 percent of these components is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv.

The operator shall keep records of the monthly inspection, subsequent repair, and re-inspection, in a manner approved by the District. Records shall be kept and maintained for at least five years, and shall be made available to the Executive Officer upon request.

For all new components in VOC service as defined by Rule 1173, a leak greater than 500 ppm but less than 1,000 ppm, measured as methane above background using EPA Method 21, shall be repaired within 14 days of detection. A leak greater than 1,000 ppm shall be repaired according to Rule 1173.

The operator shall provide to the District, prior to initial startup, a list of all non-leakless type valves that were installed. The list shall include the tag numbers for the valves and reasons why leakless valves were not used. The operator shall also submit a complete as-built piping and instrumentation diagram(s) and copies of requisition data sheets or field inspection surveys for all non-leakless type valves.

The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]

[Systems subject to this condition: Process 1, System 5; Process 5, System 2, 4, 5; Process 9, System 1; Process 14, System 11]

S31.X2 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 575837:

All new valves in VOC service shall be bellows seal valves except: (1) those specifically exempted by Rule 1173; (2) those in heavy liquid service as defined in Rule 1173; or (3) those approved by the District in the following applications: control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where valve failure could pose safety hazard (e.g., drain valves with valve stems in horizontal position), retrofits/special applications with space limitations, and valves not commercially available.

All new components in VOC service as defined by Rule 1173, except those specifically exempted by Rule 1173, shall be distinctly identified from other components through their tag numbers (e.g., numbers ending in the letter "N2"), and shall be noted in the records.

All new open-ended lines shall be equipped with cap, blind flange, plug, or a second valve.

All new pressure relief valves shall be connected to closed vent system or equipped with a rupture disc.

All new pumps shall utilize double seals and be connected to a closed vent system.

All new compressors shall be equipped with a seal system with a higher pressure barrier fluid.

All new process drains shall be equipped with water seal, or a closed vent system and control device complying with the requirements of 40CFR60 Subpart QQQ Section 60.692-5.

All new valves and flanges in VOC service as defined by Rule 1173, except those specifically exempted by the rule, shall be inspected monthly using EPA Method 21.

If 98.0 percent or greater of the new non-bellows seal valves and the new flanges population inspected (as an aggregate) is found to leak gaseous or liquid volatile organic compounds at a rate less than 200 ppmv for two consecutive months, then the operator may change leak inspection interval for these components from monthly to quarterly with prior approval of the Executive Officer. The operator shall revert back to monthly inspection interval if less than 98.0 percent of these components is found to leak gaseous or liquid volatile organic compounds at a rate less than 200 ppmv.

The operator shall keep records of the monthly inspection, subsequent repair, and re-inspection, in a manner approved by the District. Records shall be kept and maintained for at least five years, and shall be made available to the Executive Officer upon request.

For all new components in VOC service as defined by Rule 1173, a leak greater than 200 ppm but less than 1,000 ppm, measured as methane above background using EPA Method 21, shall be repaired within 14 days of detection. A leak greater than 1,000 ppm shall be repaired according to Rule 1173.

The operator shall provide to the District, prior to initial startup, a list of all non-leakless type valves that were installed. The list shall include the tag numbers for the valves and reasons why leakless valves were not used. The operator shall also submit a complete as-built piping and instrumentation diagram(s) and copies of requisition data sheets or field inspection surveys for all non-leakless type valves.

The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]

[Systems subject to this condition: Process 19, System 9]

S31.4 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 427414, 376189:

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

The operator shall keep records of the monthly inspection (and quarterly where applicable), subsequent repair, and re-inspection, in a manner approved by the District.

All process drains shall be equipped with water seal, or a closed vent system and control device complying with the requirements of 40CFR60 Subpart QQQ Section 60.692-5.

All components in VOC service, except valves and flanges shall be inspected quarterly using EPA reference method 21. All valves and flanges in VOC service except those specifically exempted by Rule 1173 shall be inspected monthly using EPA Method 21.

If 98.0 percent or greater of the new valve and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppm for two consecutive months, then the operator may revert to a quarterly inspection program with the approval of the executive officer. This condition does not apply to leakless valves.

All valves in VOC service shall be of leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following applications: heavy liquid service, control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where failures could pose safety hazards (e.g. drain valves with valve stems in horizontal position), retrofits with space limitations, and valves not commercially available.

The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service. The operator shall also submit a complete, as built, piping and instrumentation diagram(s) and copies of requisition data sheets for all non-leakless type valves with a listing of tag numbers and reasons why leakless valves were not used.

All open-ended valves shall be equipped with cap, blind flange, plug, or a second valve.

All pressure relief valves shall be connected to closed vent system or equipped with rupture disc.

All sampling connections shall be closed-purge, closed-loop, or closed-vent system.

All components in VOC service, a leak greater than 500 ppm but less than 1,000 ppm measured as methane above background as measured using EPA Method 21, shall be repaired within 14 days of detection. A leak greater than 1,000 ppm shall be repaired according to Rule 1173.

All components are subject to 40CFR60, Subpart GGG

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 9, System 9]

S31.5 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 425810:

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

The operator shall keep records of the monthly inspection (and quarterly where applicable), subsequent repair, and re-inspection, in a manner approved by the District.

All components in VOC service, except valves and flanges, shall be inspected quarterly using EPA reference method 21. All valves and flanges in VOC service, except those specifically exempted by Rule 1173, shall be inspected monthly using EPA Method 21.

If 98.0 percent or greater of the new valve and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppm for two consecutive months, then the operator may revert to a quarterly inspection program with the approval of the executive officer. This condition does not apply to leakless valves.

All valves in VOC service shall be of leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following applications: heavy liquid service, control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where failures could pose safety hazards (e.g. drain valves with valve stems in horizontal position), retrofits with space limitations, and valves not commercially available.

All open-ended valves shall be equipped with cap, blind flange, plug, or a second valve.

All pressure relief valves shall be connected to closed vent system or equipped with rupture disc.

All sampling connections shall be closed-purge, closed-loop, or closed-vent system.

All components in VOC service, a leak greater than 500 ppm but less than 1,000 ppm measured as methane above background as measured using EPA Method 21, shall be repaired within 14 days of detection. A leak greater than 1,000 ppm shall be repaired according to Rule 1173.

All components are subject to 40CFR60, Subpart GGG

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 1, System 5]

S31.9 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 450816, 450822, 450823, 450824, 450840, 450841, 502189, 502190:

All open-ended valves shall be equipped with cap, blind flange, plug, or a second valve

All pressure relief valves shall be connected to closed vent system or equipped with rupture disc

All new process drains installed as a result of this project shall be equipped with a water seal

All sampling connections shall be closed-purge, closed-loop, or closed-vent system

All new valves in VOC service installed as a result of this project shall be of leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following applications: heavy liquid service, control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where failures could pose safety hazards (e.g. drain valves with valve stems in horizontal position), retrofits with space limitations, and valves not commercially available

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173

All accessible pumps, compressors, and atmospheric PRDs shall be audio-visually inspected once per 8 hr shift. All accessible components in light liquid/gas/vapor and pumps in heavy liquid service shall be inspected quarterly, except for pumps in light liquid service and valves in gas/vapor or light liquid service which shall be inspected monthly when required per CFR60 Subpart GGG. All inaccessible or difficult to monitor components in light liquid/gas/vapor service shall be inspected annually

The following leaks shall be repaired within 7 calendar days - All light liquid/gas/vapor components leaking at a rate of 500 to 10,000 ppm, heavy liquid components leaking at rate of 100 to 500 ppm or greater than 3 drops/minute, unless otherwise extended as allowed under Rule 1173. The following leaks shall be repaired within 2 calendar days - any leak between 10,000 to 25,000 ppm, any atmospheric PRD leaking at a rate of 200 to 25,000 ppm, unless otherwise extended as allowed under Rule 1173

The following leaks shall be repaired within 1 calendar day - any leak greater than 25,000 ppm, heavy liquid leak greater than 500 ppm, or light liquid leak greater than 3 drops per minute

If 98.0 percent or greater of the new valve and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppm for two consecutive months, the operator may revert to a quarterly inspection program with the approval of the executive officer. This condition does not apply to leakless valves

The operator shall keep records of the monthly inspection (and quarterly where applicable), subsequent repair, and re-inspection, in a manner approved by the District

The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service. The operator shall also submit a complete, as built, piping and instrumentation diagram(s) and copies of requisition data sheets for all non-leakless type valves with a listing of tag numbers and reasons why leakless valves were not used

[**RULE 1303(a)(1)-BACT, 5-10-1996**; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002]

[Systems subject to this condition: Process 8, System 2]

S31.10 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 454566, 454568, 458594, 458600, 459257 & 459286:

The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service. The valves and flanges shall be categorized by size and service.

The operator shall submit a listing of all new non-bellows seal valves which shall be categorized by tag no., size, type, operating temperature, operating pressure, body material, application, and reasons why bellows seal valves were not used.

All new valves in VOC service, except those specifically exempted by Rule 1173 and those in heavy liquid service as defined in Rule 1173, shall be bellows seal valves, except as approved by the District, in the following applications: heavy liquid service, control valve, instrument piping/tubing, applications requiring torsional valve stem motion, applications where valve failure could pose safety hazard (e.g., drain valves with valve stems in horizontal position), retrofits/special applications with space limitations, and valves not commercially available.

All new valves and major components in VOC service as defined by Rule 1173, except those specifically exempted by Rule 1173 and those in heavy liquid service as defined in Rule 1173, shall be distinctly identified from other components through their tag numbers (e.g., numbers ending in the letter "N"), and shall be noted in the records.

All new components in VOC service as defined in Rule 1173, except valves and flanges, shall be inspected quarterly using EPA reference Method 21. All new valves and flanges in VOC service, except those specifically exempted by Rule 1173, shall be inspected monthly using EPA Method 21.

If 98.0 percent or greater of the new (non-bellows seal) valves and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv for two consecutive months, then the operator may change to a quarterly inspection program with the approval of the District.

The operator shall revert from quarterly to monthly inspection program if less than 98.0 percent of the new (non-bellows seal) valves and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv.

All new components in VOC service with a leak greater than 500 ppmv but less than 1,000 ppmv, as methane, measured above background using EPA Method 21 shall be repaired within 14 days of detection. Components shall be defined as any valve, fitting, pump, compressor, pressure relief valve, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

The operator shall keep records of the monthly inspection (quarterly where applicable), subsequent repair, and re-inspection, in a manner approved by the District. Records shall be kept and maintained for at least five years, and shall be made available to the Executive Officer or his authorized representative upon request.

All open-ended valves shall be equipped with cap, blind flange, plug, or a second valve.

All pressure relief valves shall be connected to a closed vent system or equipped with a rupture disc and telltale indicator.

All pumps shall utilize double seals and be connected to a closed vent system.

All compressors to have a seal system with a higher pressure barrier fluid.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 21, System 1, 3, 6]

S46.1 The following conditions shall apply to VOC service fugitive components in this system:

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

For the purpose of this condition, existing component shall be defined as any component that was installed under a permit to construct/operate that was issued prior to June 1, 1993. New component shall be defined as any component that was installed or modified under a permit to construct that was issued between June 1, 1993 and December 27, 2001.

All new valves in VOC service shall be of leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following applications: heavy liquid service, control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where failures could pose safety hazards (e.g. drain valves with valve stems in horizontal position), retrofits with space limitations, and valves not commercially available.

All new valves and new major components, as defined in Rule 1173, shall be physically identified in the field with special marking that distinguishes the components from existing. Additionally all new components shall be distinctly identified from existing components through their tag numbers (e.g. numbers ending in the letter "N"), and shall be noted in the records.

All new components in VOC service with a leak greater than 500 ppm but less than 1,000 ppm, as methane, measured above background using EPA Method 21, shall be repaired within 14 days of detection. A leak greater than 1,000 ppm shall be repaired according to Rule 1173.

All new pressure relief valves shall be connected to closed vent system or equipped with rupture disc.

All new sampling connections shall be closed-purge, closed-loop, or closed-vent system.

All components are subject to 40CFR60, Subpart GGG.

[**RULE 1173, 5-13-1994; RULE 1173, 2-6-2009; RULE 1303(a)(1)-BACT, 5-10-1996;**

RULE 1303(b)(2)-Offset, 5-10-1996; 40CFR 60 Subpart GGG, 6-2-2008]

[Systems subject to this condition: ~~Process 5, System 5; Process 9, System 1, 9~~]

S46.2 The following conditions shall apply to VOC service fugitive components in this system:

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

For the purpose of this condition, existing component shall be defined as any component that was installed under a permit to construct/operate that was issued prior to June 1, 1993. New component shall be defined as any component that was installed or modified under a permit to construct that was issued between June 1, 1993 and December 27, 2001.

The operator shall provide to the District, no later than August 29, 2003, a complete, as built, process instrumentation diagram(s) with a listing showing by functional grouping, location, type, accessibility, and application of each new valve in VOC service. The operator shall provide copies of requisition data sheets for all non-leakless type valves with a listing of tag numbers and reasons why leakless valves were not used.

The operator shall provide to the District, no later than August 29, 2003, a list of the following components broken down into the categories contained in District Form E-

18A entitled "Fugitive Component Count": existing components, new components proposed to be installed under applicable permit(s) to construct, and new components that were actually installed under applicable permit(s) to construct.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: ~~Process 5, System 5; Process 14, System 11~~]

S46.3 The following conditions shall apply to VOC service fugitive components in this system:

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

For the purpose of this condition, existing component shall be defined as any component that was installed under a permit to construct/operate that was issued prior to June 1, 1993. New component shall be defined as any component that was installed or modified under a permit to construct that was issued between June 1, 1993 and December 27, 2001.

All new valves in VOC service shall be of leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following applications: heavy liquid service, control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where failures could pose safety hazards (e.g. drain valves with valve stems in horizontal position), retrofits with space limitations, and valves not commercially available.

All new valves and new major components, as defined in Rule 1173, shall be physically identified in the field with special marking that distinguishes the components from existing. Additionally all new components shall be distinctly identified from existing components through their tag numbers (e.g. numbers ending in the letter "N"), and shall be noted in the records.

All new components in VOC service with a leak greater than 500 ppm but less than 1,000 ppm, as methane, measured above background using EPA Method 21, shall be repaired within 14 days of detection. A leak greater than 1,000 ppm shall be repaired according to Rule 1173.

All new pressure relief valves shall be connected to closed vent system or equipped with rupture disc.

All new sampling connections shall be closed-purge, closed-loop, or closed-vent system.

[**RULE 1173, 5-13-1994; RULE 1173, 2-6-2009; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: ~~Process 14, System 11~~]

S46.4 The following conditions shall apply to VOC service fugitive components in this system:

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

For the purpose of this condition, existing component shall be defined as any component that was installed under a permit to construct/operate that was issued prior to June 1, 1993. New component shall be defined as any component that was installed or modified under a permit to construct that was issued on or after June 1, 1993.

All new valves in VOC service shall be of leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following application: heavy liquid service, control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where failures could pose safety hazards (e.g. drain valves with valve stem in horizontal position), retrofits with space limitations, and valves not commercially available.

All new valves and new major components, as defined in Rule 1173, shall be physically identified in the field with special marking that distinguishes the components from existing. Additionally all new components shall be distinctly identified from existing components through their tag numbers (e.g. number ending in the letter "N"), and shall be noted in the records.

All new components in VOC service with a leak greater than 500 ppm but less than 1,000 ppm, as methane, measured above background using EPA Method 21, shall be repaired within 14 days of detection. A leak greater than 1,000 ppm shall be repaired according to Rule 1173.

All new pressure relief valves shall be connected to closed vent system or equipped with rupture disc.

All new sampling connections shall be closed-purge, closed-loop, or closed-vent system.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 1, System 6; Process 5, System 5; Process 9, System 1, 9; Process 14, System 11]

S56.1 Vent gases from all affected devices of this process/system shall be directed to a gas recovery system, except for the venting of gases from equipment specifically identified in a permit condition, and for the following events for which vent gases may be directed to a flare:

1) Vent gases during an Emergency as defined in Rule 1118;

2) Vent gases resulting from Planned Shutdowns, Startups and/or Turnarounds as defined in Rule 1118, provided that the owner/operator follows the applicable options and any associated limitations to reduce flaring that were identified, evaluated and most recently submitted by the owner/operator to the Executive Officer pursuant to Rule 1118, or any other option(s) which reduces flaring for such events; and

3) Vent gases due to and resulting from an Essential Operating Need, as defined in Rule 1118.

The evaluation of options to reduce flaring during Planned Shutdowns, Startups and/or Turnarounds shall be updated annually to reflect any revisions, and submitted to the Executive Officer in the first quarter of each year, but no later than March 31st of that year.

This process/system shall not be operated unless its designated flare(s) are in full use and have valid permits to receive vent gases from this process/system.

Vent gases shall not be released to the atmosphere except from the existing safety devices or relief valves on the following equipment:

Process 1, System 2: 10, 12, 14
Process 1, System 3: 19, 20, 24 to 26
Process 1, System 5: 35, 39, 41, 42, 2726

Process 1, System 6: 43, 49, 57, 58
Process 1, System 7: 59, 60, 61, 62
Process 2, System 1: 74, 77, 2388
Process 2, System 2: 82, 89, 90, 92, 2389
Process 2, System 3: 94, 95
Process 2, System 5: 98, 101, 102
Process 2, System 6: 111, 112, 113
Process 2, System 11: 159, 160
Process 3, System 1: 164 to 167, 170, 172 to 181, 184, 1336 to 1349, 2382, 2387
Process 3, System 2: 186, 188, 189, 191, 196, 199, 201, 204, 1352 to 1355
Process 3, System 4: 241
Process 3, System 6: 242, 245 to 247, 249
Process 3, System 7: 1363
Process 4, System 1: 253 to 256, 258, 262, 265, 268, 270, 272, 277, 278, 282, 283. 287, 1364, 1366, 1367, 1372, 1374 to 1376, 1378 to 1381
Process 4, System 2: 291, 1400 to 1403
Process 4, System 3: 292, 293, 297, 299
Process 4, System 4: 302, 304
Process 4, System 5: 308, 310, 311
Process 4, System 7: 1975 to 1977, 1980, 1981, 1986
Process 5, System 1: 314 to 317, 319, 320, 323 to 332
Process 5, System 2: 335 to 338, 340, 343, 348 to 353
Process 5, System 3: 356, 360, 1413
Process 5, System 4: 401, 406, 407, 412, 414
Process 6, System 1: 426, 427, 429, 431, 434, 435, 437, 440, 444, 445, 455 to 456, 458, 460
Process 6, System 2: 462, 469, 474 to 475, 477 to 481, 483, 486
Process 6, System 3: 490, 494, 495, 498, 501, 503, 506, 507, 509, 510, 512, 513, 518, 520, 521, 525 to 528
Process 7, System 1: 542 to 548, 550, 552 to 558, 560, 562 to 569
Process 7, System 2: 2892, 2893
Process 8, System 1: 583, 584, 593 to 597
Process 8, System 2: 608, 610, 612 to 614, 622, 624
Process 9, System 1: 631, 632, 638 to 652, 659 to 663, 666 to 668, 1482, 1483, 1486 to 1488, 1491, 1493 to 1495, 1497 to 1502, 1528, 1533 to 1536, 2019
Process 9, System 2: 672 to 681, 685
Process 9, System 9: ~~637~~, 653, ~~656, 658~~, 664
Process 10, System 1: 706
Process 10, System 2: 709, 711 to 715, 720, 721
Process 10, System 3: 725
Process 11, System 1: 730
Process 12, System 1: 756, 759

Process 12, System 2: 760 to 762, 764
Process 12, System 3: 765 to 770
Process 12, System 4: 771, 772, 774
Process 12, System 8: 785, 790, 2365, 2366
Process 12, System 9: 794, 797 to 799
Process 12, System 10: 806
Process 12, System 12: 815, 818
Process 12, System13: 823, 826, 828
Process 12, System 16: 830
Process 12, System 22: 853, 854
Process 12, System 24: 860, 861, 863, 864, 865
Process 12, System 25: 866, 867, 869, 870, 871, 2003
Process 12, System 27: 873 to 875
Process 15, System 7: 1644 to 1646, 1648, 1649
Process 16, System 3: 2115 to 2120, 2353, 2394
Process 21, System 1: 1304
Process 21, System 2: 1307
Process 21, System 4: 1315, 1316, 1319, 1323 to 1325, 1659

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 1, System 5; Process 5, System 2, 4, 5; Process 8, System 2; Process 9, System 1, 9; Process 14, System 11, Process 19, System 9]

S58.2 South Area Flare System (Coker Flare) shall only be used to receive and handle vent gases from the following Process(es) and System(s):

Coking Units (Process: 2, System: 1 & 2)
Coker Blowdown Facility (Process: 2, System: 3)
Coker Gas Compression & Absorption Unit (Process: 2, System: 5)
Blowdown Gas Compression System (Process: 2, System: 6)
Coker Gas Treating/H2S Absorption Unit (Process: 2, System: 11)
Fluid Catalytic Cracking Units (Process: 3, System: 1, 2 & 3)
Propylene Tetramer Unit (Process: 3, System: 6)
Superfractionation Unit (Process: 4, System 1)
Naphtha Splitter Unit (Process: 4, System: 2)
Light Ends Depropanizer Unit (Process: 4, System: 3)
Straight Run Light Ends Depropanizer Unit (Process: 4, System: 4)
North Area De-isobutanizer Unit (Process: 4, System: 5)
Coker Gasoline Fractionation Unit (Process: 4, System: 7)
Liquid Recovery Unit (Process: 4, System: 8)
Light Gasoline Hydrogenation Unit (Process: 5, System: 4)

Catalytic Reformer Units (Process: 6, System: 1, 2, & 3)
Alkylation Unit (Process: 9, System: 1)
Iso-Octene Unit (Process: 9, System: 9)
MDEA Regeneration Units (Process: 12, System: 9, 10, 11, 12, & 13)
North & South Sour Water Treatment Systems (Process: 12, System: 14 & 15)
Sulfur Recovery Units (Process: 13, System: 1, 2, 3, & 4)
Claus Tail Gas Treating Units (Process: 13, System: 5 & 7)
Mixed Light Ends Tank Car Loading/Unloading (Process: 14, System: 2)
Refinery Interconnection System (Process 19, System 9)
Refinery Vapor Recovery System (Process: 21, System: 4)
Flare Gas Recovery System (Process: 21, System: 10)

The flare gas recovery system shall be operated in full use when any of the above Process(es) and System(s) is in operation. Full use means one of two compressor trains is online at any given time, except during planned startups or shutdowns when both compressors trains shall be online.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 21, System 1]

S58.4 Hydrocracker Flare System shall only be used to receive and handle vent gases from the following Process(es) and System(s):

Light Ends Depropanizer (Process: 4, System: 3)
Jet Fuel Hydrotreating Unit (Process: 5, System: 1)
Mid-Barrel Desulfurizer Unit (Process: 5, System: 2)
Light Gasoline Hydrogenation Unit (Process: 5, System: 4)
Catalytic Reformer Units (Process: 6, System: 1, 2, & 3)
Hydrogen Plant (Process: 7, System 1)
Hydrocracking Units (Process: 8, System: 1 & 2)
LPG Recovery System (Process: 10, System: 2)
Liquid Petroleum Gas Drying Facilities (Process: 10, System: 3)
MDEA Regeneration Systems (Process: 12, System: 9 & 10)
If HC Flare is being utilized to back up the FCCU Flare, FCCU, FCCU Gas Plant & FCCU Gas Compression Unit (Process: 3, System: 1, 2 & 3)
If HC Flare is being utilized to back up the FCCU Flare, Propylene Tetramer Unit (Process: 3, System: 6)
If HC Flare is being utilized to back up the FCCU Flare, Liquids Recovery Unit (Process: 4, System: 8)
If HC Flare is being utilized to back up the FCCU Flare, Catalytic Polymerization Unit (Process: 9, System: 2)

If HC Flare is being utilized to back up the FCCU Flare, Fuel Gas Mix System (Process: 10, System: 1)
If HC Flare is being utilized to back up the FCCU Flare, North Sour Water Treatment Unit (Process: 12, System: 14)

The flare gas recovery system shall be operated in full use when any of the above Process(es) and System(s) is in operation. Full use means one of two compressor trains is online at any given time, except during planned startups or shutdowns when both compressors trains shall be online.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 21, System 3]

S58.6 Refinery No. 5 Flare System shall only be used to receive and handle vent gases from the following Process(es) and System(s):

No. 1 Crude Unit (Process: 1, System 1)
Superfractionation Unit (Process: 4, System: 1)
Coker Gasoline Fractionation Unit (Process: 4, System: 7)
C3 Splitter Unit (Process: 4, System: 9)
Naphtha HDS Unit (Process: 5, System: 5)
Naphtha HDS Reactor Heater (Process: 5, System: 6)
Hydrogen Plant No. 2 (Process: 7, System: 2)
Alkylation Unit (Process 9, System 1)
C5 Alkylation Depentanizer Unit (Process: 9, System: 6)
C5 Alkylation Unit (Process: 9, System: 7)
Naphtha Isomerization Unit (Process: 9, System: 8)
Butane Isomerization Unit (Process: 9, System: 10)
UOP Merox Unit (Process: 12, System: 8)
LPG Tank Truck Loading/Unloading Rack (Process: 14, System: 10)
LPG Rail Car Loading/Unloading Rack (Process: 14, System: 11)
Flare Gas Recovery System (Process: 21, System: 10)
INEOS POLYPROPYLENE LLC ID 124808 (Process: 1, System: 1, 2, 3, 5, 6, & 9)

The flare gas recovery system shall be operated in full use when any of the above Process(es) and System(s) is in operation. Full use means one of two compressor trains is online at any given time, except during planned startups or shutdowns when both compressors trains shall be online.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**]

[Systems subject to this condition: Process 21, System 6]

A63.30 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
ROG	Less than or equal to ~~36~~ 48.67 LBS PER DAY
CO	Less than or equal to ~~21~~ 243.33 LBS PER DAY
PM	Less than or equal to ~~106~~ 52.14 LBS PER DAY

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: D63]

A99.X1 The 2.62 Lbs/hr NOx emission limit(s) shall not apply when this equipment is operating during startup and shutdown modes.

Each startup event shall not exceed 48 hours (not including refractory dry out period of up to 48 additional hours) and each shutdown event shall not exceed 24 hours.

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition: D63]

A195.X1 The 2.62 LBS/HR NOx emission limit(s) is averaged over 24 hours.

[**RULE 2005, 6-3-2011**]

[Devices subject to this condition: D63]

B61.4 The operator shall not use fuel gas, except uncombined natural gas which is not regulated by the condition, containing the following specified compounds:

COMPOUND	ppm by volume
H2S greater than	160

[**40CFR 60 Subpart J, 6-24-2008**]

[Devices subject to this condition: ~~C1661~~]

B61.8 The operator shall not use fuel gas containing the following specified compounds:

COMPOUND	ppm by volume
H2S greater than	162

The 162 ppmv limit is averaged over three hours, excluding any vent gas resulting from an emergency malfunction, process upset or relief valve leakage

[**40CFR 60 Subpart Ja, 6-24-2008**]

[Devices subject to this condition: C1302, C1308, C1661]

C1.X1 The operator shall limit the heat input to no more than 360 MM Btu per hour.

[**RULE 1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition: D63]

D12.15 The operator shall install and maintain a(n) thermocouple to accurately indicate the presence of a flame at the pilot light.

The operator shall also install and maintain a device to continuously record the parameter being measured.

Thermocouple shall be the primary pilot flame detector. Infrared/ultraviolet detector may serve as back up detector when thermocouple is taken out of service for maintenance or repair.

[**RULE 1118, 11-4-2005; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; 40CFR 60 Subpart A, 4-4-2014**]

[Devices subject to this condition: C1302, C1308, C1661]

D29.3 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
ROG emissions	Approved District method	District-approved averaging time	Outlet
PM emissions	District method 5.1	1 hour	Outlet

The test(s) shall be conducted at least once every three years.

The test shall be conducted when the equipment is operating under normal conditions.

The test shall be conducted to demonstrate compliance with the emission limits specified in condition for this equipment.

[**RULE 1303(b)(2)-Offset, 5-10-1996; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997**]

[Devices subject to this condition: ~~D63~~]

D29.X1 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
ROG emissions	District Method 25.1 or 25.3	District-approved averaging time	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1 or 10.1	District-approved averaging time	Outlet of the SCR serving this equipment
PM emissions	District Method 5.1, 5.2 or 5.3	District-approved averaging time	Outlet of the SCR serving this equipment
NOx emissions	District Method 100.1 or 10.1	District-approved averaging time	Outlet of the SCR serving this equipment

The test(s) shall be conducted within 90 days after achieving maximum production rate, but no later than 180 cumulative days of operation after the date of issuance of the Permit to Construct (A/N 567649) and at least annually thereafter.

The test shall be conducted when this equipment is operating at 80 percent or greater of the maximum design capacity.

The test shall be conducted to determine the oxygen concentration.

For NOx, source test data may be substituted with CEMS data from a RECLAIM certified CEMS.

The test shall be conducted to demonstrate compliance with the emission limits for this equipment including with emissions rates limits for PM, CO, and VOC, in units of lbs/MMscf.

The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted after District approval of a source test protocol submitted in accordance with Section E- Administrative Conditions.

The test shall be conducted and test report submitted to the District in accordance with Section E - Administrative Conditions.

[**RULE 1303(b)(2)-Offset, 5-10-1996; RULE 2005, 4-20-2001; RULE 407, 4-2-1982**]

[Devices subject to this condition: D63]

~~D90.16~~ ~~The operator shall periodically monitor the H2S concentration at the inlet of this device according to the following specifications:~~

~~The Alternative Monitoring Plan (AMP) approved by the United States Environmental Protection Agency (USEPA) on March 27, 2008 for the periodic monitoring and reporting of H2S concentration for refinery gas stream to No. 5 Flare~~

~~In addition, the operator shall also comply with all other requirements of the AMP issued by the USEPA on March 27, 2008 for No. 5 Flare~~

~~[**40CFR 60 Subpart A, 6-13-2007; 40CFR 60 Subpart J, 6-24-2008**]~~

~~[Devices subject to this condition: C1661]~~

D323.1 The operator shall conduct an inspection for visible emissions from all stacks and other emission points of this equipment whenever there is a public complaint of visible emissions, whenever visible emissions are observed, and on a bi-weekly basis, at least, unless the equipment did not operate during the entire bi-weekly period. The routine bi-weekly inspection shall be conducted while the equipment is in operation and during daylight hours.

If any visible emissions (not including condensed water vapor) are detected that last more than three minutes in any one hour, the operator shall verify and certify within 24 hours that the equipment causing the emission and any associated air pollution control equipment are operating normally according to their design and standard procedures and under the same conditions under which compliance was achieved in the past, and either:

1). Take corrective action(s) that eliminates the visible emissions within 24 hours and report the visible emissions as a potential deviation in accordance with the reporting requirements in Section K of this permit; or

2). Have a CARB-certified smoke reader determine compliance with the opacity standard, using EPA Method 9 or the procedures in the CARB manual "Visible Emission Evaluation", within three business days and report any deviations to AQMD.

The operator shall keep the records in accordance with the recordkeeping requirements in Section K of this permit and the following records:

1). Stack or emission point identification;

2). Description of any corrective actions taken to abate visible emissions;

3). Date and time visible emission was abated; and

4). All visible emission observation records by operator or a certified smoke reader.

[**RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 401, 3-2-1984;** RULE 401, 11-9-2001]

[Devices subject to this condition: C1302, C1308, C1661]

D328.1 The operator shall determine compliance with the CO emission limit(s) either: (a) conducting a source test at least once every five years using AQMD Method 100.1 or 10.1; or (b) conducting a test at least annually using a portable analyzer and AQMD-approved test method. The test shall be conducted when the equipment is operating under normal conditions to demonstrate compliance with the CO emission limit(s). The operator shall comply with all general testing, reporting, and recordkeeping requirements in Sections E and K of this permit.

[**RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982**]

[Devices subject to this condition: D63]

E193.3 The operator shall operate and maintain this equipment according to the following specifications:

The operator shall comply with all applicable requirements specified in Subpart A of the 40CFR60

[**40CFR 60 Subpart A, 4-4-2014**]

[Devices subject to this condition: C1302, C1308, C1661]

E193.4 The operator shall install this equipment according to the following specifications:

A blind flange shall be installed at the connection to this ejector from the flash drum at a location accessible for inspection.

This equipment shall be operated only during refinery turnaround in accordance with Rule 1123.

[**RULE 1123, 12-7-1990**]

[Devices subject to this condition: D2648]

E193.25 The operator shall restrict the operation of this equipment as follows:

The flare may serve to back up the FCCU Flare only when the FCCU Flare is taken out of service during the planned shutdown periods, and all of the following criteria are met:

The following units shall not be in operation: Hydrocracker Units (Process 8, System 1 & 2), Hydrogen Plant (Process 7, System 1).

When the HC Flare is serving as backup to the FCC Flare, only the following units shall relief to the flare:

Jet Fuel Hydrotreating Unit (Process 5, System 1), Mid-Barrel Desulfurizer Unit (Process 5, System 2), Light Gasoline Hydrogenation Unit (Process 5, System 4), LPG Recovery System (Process 10, System 2), LPG Drying Facilities (Process 10, System 3), Catalytic Reforming Units (Process 6, Systems 1, 2 & 3), MDEA Regeneration Systems No 1 & 2 (Process 12, Systems 9 & 10),

FCCU, FCCU Gas Plant & FCCU Gas Compression Unit (Process 3, Systems 1, 2 & 3), Propylene Tetramer Unit (Process 3, System 6), Liquid Recovery Unit (Process 4, System 8), Catalytic Polymerization Unit (Process 9, System 2), Fuel

Gas Mix Drum System (Process 10, System 1), North Sour Water Treatment Unit (Process 12, System 14).

For No. 9 Cooling Tower failure scenario, the relief loads shall not exceed the hydraulic capacity of the flare. If requested by District personnel, the operator shall provide analysis, or, if one is not available, perform hydraulic modeling analysis of the relief event to demonstrate compliance with this condition.

In No. 9 Cooling Tower failure scenario, only the following units shall relief to the flare: FCCU, FCCU Gas Plant & FCCU Gas Compression (Process 3, Systems 1, 2 & 3) and MDEA Regeneration Systems No. 1 & 2 (Process 12, System 9 & 10).

All other relief events to the flare shall not exceed the smokeless capacity of a flare, which is designed for 417,000 lb/hr, except for periods not to exceed a total of five minutes during any two consecutive hours. If requested by District personnel, the operator shall provide analysis, or, if one is not available, perform hydraulic modeling analysis of the relief event to demonstrate compliance with this condition.

The operator shall not utilize the HC Flare to back up the FCCU Flare for a period greater than 30 days, unless otherwise approved in writing by the Executive Officer.

The operator shall notify the District a minimum of 10 days before the start of the planned shutdown of the FCCU Flare. This notification shall indicate the estimated duration of the shutdown.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: C1308]

E204.7 The operator shall operate the valve to atmosphere according to the following specifications:

The valve shall be kept closed during normal operation and shall only be used for steaming out the tower during turnaround maintenance activities.

[**RULE 1123, 12-7-1990**]

[Devices subject to this condition: D1530]

E336.8 The operator shall vent the vent gases from this equipment as follows:

All emergency vent gases shall be directed to the South Area Flare System (Process 21, System 1).

This equipment shall not be operated unless the flare system is in full use and has a valid permit to receive vent gases from this equipment.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: ~~D2719~~]

H23.1 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, SUBPART	J

[**40CFR 60 Subpart J, 9-12-2012**]

[Devices subject to this condition: ~~C1661~~]

H23.3 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173
VOC	40CFR60, SUBPART	GGG

[**RULE 1173, 2-6-2009**; **40 CFR 60 Subpart GGG, 6-2-2008**]

[Devices subject to this condition: ~~D2462, D2483, D2485, D2488, D2495,~~ ~~D2496,~~ D2503, D2542, D2544, D2547, ~~D2539~~]

H23.12 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
Benzene	40CFR61, SUBPART	FF

[**40CFR 61 Subpart FF, 12-4-2003**]

[Devices subject to this condition: D406, D408, D1424, ~~C1308, D1309, C1661, D1662~~]

H23.29 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
SOX	District Rule	1118
VOC	District Rule	1118

[**RULE 1118, 11-4-2005**]

[Devices subject to this condition: C1302, C1308, C1661]

H23.34 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	465
Sulfur Compounds	District Rule	465

[**RULE 465, 8-13-1999**]

[Devices subject to this condition: D2940, D2941, D2942, D2943]

H23.36 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173
ROG	40CFR60, SUBPART	GGGa

[**RULE 1173, 2-6-2009**; **40CFR 60 Subpart GGGa, 6-2-2008**]

[Devices subject to this condition: D2462, D2483, D2485, D2488, D2495, D2496, D2539, DX11]

H23.39 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, SUBPART	Ja

[**40CFR 60 Subpart Ja, 6-24-2008**]

[Devices subject to this condition: C1302, C1308, C1661]

K67.2 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Fuel heating value

Fuel rate

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: D63]

L341.X1 Within 90 days after startup of this equipment the following devices shall be removed from operation:

(D96) FCCU Regenerator at Tesoro LAR Wilmington Operations (Facility ID: 800436)
(D92) H-2 Steam Superheater at Tesoro LAR Wilmington Operations (Facility ID: 800436)
(D112) CO Boiler at Tesoro LAR Wilmington Operations (Facility ID: 800436)
(D89) H-3 Fresh Feed Heater at Tesoro LAR Wilmington Operations (Facility ID: 800436)
(D90) H-4 Hot Oil Loop Reboiler at Tesoro LAR Wilmington Operations (Facility ID: 800436)
(D91) H-5 Fresh Feed Heater at Tesoro LAR Wilmington Operations (Facility ID: 800436)
(D1664) B-1 Startup Heater at Tesoro LAR Wilmington Operations (Facility ID: 800436)

[**RULE 1313, 12-7-1995**]

[Devices subject to this condition: DX1, DX2, DX8, DX9, DX10, DX11, D632, D637, D658, D656, D2726]

LIST OF ATTACHMENTS

ATTACHMENT #1: EMISSIONS REDUCTIONS FROM TAKING FCCU AND ASSOCIATED HEATERS OUT OF SERVICE

ATTACHMENT #2: EQUIPMENT SPECIFICATIONS AND DRAWINGS

ATTACHMENT #3: TOXIC AIR CONTAMINANT EMISSIONS AND RULE 1401 SCREENING HEALTH RISK ASSESSMENT

ATTACHMENT #4: PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY ANALYSIS

ATTACHMENT #5: CORRESPONDENCES

ATTACHMENT #6 (A/N 567649): No. 51 Vacuum Distillation Unit Feed Heater (D63) NO_x Emissions, Fuel Input, and Heat Input over two years prior to application submittal

ATTACHMENT #6 (A/Ns 575839, 575840, 575841): Flare Capacity Analysis Worksheet

ATTACHMENT #6 (A/Ns 567643, 567645, 567646, 567647, 567648, 575837, 578249): New PSVs to be added under the LARIC Project and Venting Arrangements

ATTACHMENT #7: STATEWIDE CERTIFICATION OF COMPLIANCE WITH THE CLEAN AIR ACT FOR ALL TESORO MAJOR STATIONARY SOURCES